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COVER LETTER

Wildflower Energy, LP
4320 La Jolla Village Drive
Suite 250
San Diego, CA 92122

Mr. Earnest Davis
San Diego Air Pollution Control District
9150 Chesapeake Drive
San Diego, CA 92123

Regarding: Wildflower Energy Larkspur Permit Revision (Application No. 976094)
Application for a Simple Cycle Peaking Plant, Harvest Road, Otay Mesa

Dear Mr. Davis:

As you are aware, on February 23, 2001 Wildflower Energy, LP submitted an application for Authority to Construct a 49.9 MW peaker plant north of the San Diego Gas & Electric Border Substation to the San Diego Air Pollution Control District (District). The project is known as the Wildflower Larkspur Project.

Wildflower Energy, LP wishes to install a second 49.9 MW GE LM6000 PC Sprint unit at the Larkspur site. The unit will be identical to the initial unit. Wildflower Energy, LP is therefore submitting the attached addendum to Application Number 976094 for Authority to Construct the additional unit. The exhaust of the second unit will be controlled with a highly efficient, Selective Catalytic Reduction (SCR) system designed to achieve BACT levels of less than 5 ppm NOx, corrected to 15% O2. Because the new unit will meet the same emission standard proposed for the initial turbine at the site, no new BACT evaluation has been prepared. For your convenience, we have provided a copy of the BACT submittal for the initial unit which has been updated accordingly. Furthermore, no new regulatory evaluation is required as the new unit will be subject to the same requirements as the initial unit. With two units, the Larkspur facility is designed as a peaking facility; however, the facility's NOx emissions will not exceed 50 tons per year.

As we have discussed, both units will be equipped with a Turner SCR, and will be available to be fired on both natural gas as the main fuel and distillate fuel solely in the event of a natural gas curtailment.

As we discussed in the initial application for the initial turbine, Governor Davis' Executive Orders require all of us to work expeditiously to develop new sources of electric energy, and require those energy facilities on line by July 1, 2001. Because of this fast track scheduling, and the high demand for catalyst material across the country, there is a possibility the catalyst may be delivered late, after the energy facility is scheduled to come online. As we have also discussed with you, the District has agreed to support our variance petition to the Hearing

Board, if needed, to allow operation of the turbine prior to delivery of the catalyst. To support the District, we have evaluated the impact of operating both turbines without the catalyst (estimated at 25 ppm NOx at full load) to account for potential impacts during the commissioning period should operation without the catalyst be necessary. While the Project Team would prefer that this issue be addressed in the permit itself, we understand the constraints placed upon the District with regard to this issue by statute, and we appreciate the District's flexibility in this matter.

The following information is enclosed herewith:

- General Permit Application Form (modified to include the second peaking unit)
- Gas Turbine Application Form for the additional gas turbine
- Emission Estimates for both turbines
- Air Quality Impact Assessment and Rule 1200 Evaluation, revised to include reference to second turbine (and includes select sections from initial submittal)
- Site Plan and Layout
- BACT Evaluation (copy of initial application BACT submittal)

Not included in this submittal is a fee estimate form for which we understand typically accompanies any submittal. Please consider the attached to be a revision to the current application for the site and provide a fee estimate for additional time and materials necessary to process this application.

Thank you very much for your time and support of this project. Please contact the undersigned or Mike Evans at (858) 320-1503 if you have any questions regarding this application.

Sincerely,

John Jones
Vice President

APCD Application Forms

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

PERMIT / REGISTRATION APPLICATION

APPLICATION INSTRUCTIONS - FORM APCD 16

GENERAL

1. The owner or designated agent must complete and sign this multi-copy form and file it with one copy of all attachments, required supplementary forms, drawings and the appropriate fee.
2. The appropriate fee (payable to "County of San Diego APCD") shall be forwarded with this Permit/Registration Application. Application processing will not begin until the full required fee has been received. Excess fees will be refunded upon completion of the application process. If you do not know the appropriate fee or need to discuss the information required, please contact the District at (858) 650-4700 and ask for the Engineering Division.

REASON FOR SUBMITTAL OF APPLICATION

1. New Installation - check if you are installing equipment that does not currently have a District Permit to Operate.
2. Existing Unpermitted Equipment or Rule 11 Change - check if applying for installed existing equipment that is currently unpermitted or equipment that is now subject to District Rules due to Rule 11 changes.
3. Modification of Existing Permitted Equipment - check if you are making a change to equipment with a current District Permit to Operate. (List affected PO #(s) on line 12)
4. Amendment to Existing Authority to Construct or Permit/Registration Application - check this line if you are amending a previously submitted application form or if amending a current Authority to Construct. (List affected Application #(s) on line 12)
5. Change of Equipment Location - check if you are moving non-portable equipment with a current District Permit to Operate. (List affected PO #(s) on line 12)
6. Change of Equipment Ownership - check if you are now the owner of equipment with a current District Permit to Operate under a different owner. (List affected PO #(s) on line 12)
7. Change of Permit Conditions - check if equipment with a current Permit to Operate requires changes to the existing operating conditions. (List affected PO #(s) on line 12)
8. Change Permit to Operate Status to Inactive - check if you wish to maintain your current Permit to Operate but are not going to operate the equipment. (List affected PO #(s) on line 12)
9. Banking Emissions - check if you are retiring equipment with a current District Permit to Operate and wish to bank the emissions for future credits. (List affected PO #(s) on line 12)
10 Registration of Portable Equipment - check this line if you are applying for registration of portable equipment.
11. Other - check for any action not covered by #(s) 1 thru 10.
12. List affected AP/PO#(s) - if you checked #'s 3 or 5-9, list current Permit to Operate Number(s) affected or if you checked #4, list existing Application number whether or not an Authority to Construct has been issued.

APPLICANT INFORMATION

13 thru 17 are self-explanatory.
18 thru 27 are self-explanatory, complete Items B, C, and D only if different from Item A.

EQUIPMENT/PROCESS INFORMATION

Check Stationary (e.g. gasoline service site, dry cleaning facility, etc.) or Portable (abrasive blast pot, roofing kettle, etc.) depending upon the type of equipment for which you are filing an application. Also check Yes if the equipment is portable and will operate more than 180 consecutive days at a single site. Otherwise, check No.

28 thru 36 are self-explanatory.

APCD 16 (Rev. 10/97)

SAN DIEGO AIR POLLUTION CONTROL DISTRICT
9150 CHESAPEAKE DRIVE, SAN DIEGO CA 92123-1096
PHONE (858) 650-4700 • FAX (858) 650-4659

PERMIT / REGISTRATION APPLICATION

FILING THIS APPLICATION DOES NOT GRANT PERMISSION TO CONSTRUCT OR TO OPERATE EQUIPMENT

IMPORTANT REMINDERS: Read instructions on the reverse side of this form prior to completing this application. Please ensure that all of the following are included before you submit the application:
☐ Appropriate Permit Fee ☐ Completed Supplemental Form(s) ☐ Signature on Application

REASON FOR SUBMITTAL OF APPLICATION: (check the appropriate item and enter Application (AP) or Permit to Operate (PO) number if required)

1. ☒ New Installation 2. ☐ Existing Unpermitted Equipment or Rule 11 Change 3. ☐ Modification of Existing Permitted Equipment
4. ☒ Amendment to Existing Authority to Construct or AP 5. ☐ Change of Equipment Location 6. ☐ Change of Equipment Ownership
7. ☐ Change of Permit Conditions 8. ☐ Change Permit to Operate Status to Inactive 9. ☐ Banking Emissions
10. ☐ Registration of Portable Equipment 11. ☒ Other (Specify) CIF Larkspur See Site Map
12. List affected AP/PO#(s): ______

APPLICANT INFORMATION

13. Name of Business (DBA) Wildflower Energy LP
14. Nature of Business Power Generation
15. Does this organization own or operate any other APCD permitted equipment at this or any other adjacent locations in San Diego County? ☒Yes ☐No
If yes, list assigned location ID's listed on your PO's Application for permit NO 976094
16. Type of Ownership ☐ Corporation ☒ Partnership ☐ Individual Owner ☐ Government Agency ☐ Other ______
17. Name of Legal Owner (if different from DBA) ______

		A. Equipment Owner	B. Authority to Construct (if different from A)
18.	Name	Wildflower Energy LP	
19.	Mailing Address	4320 La Jolla Village Dr, Suite 250	
20.	City	San Diego	
·.	State	Ca Zip 92122	Zip
2.	Phone	(858) 320 1500 FAX (858) 320 1550	( ) FAX ( )

		C. Permit to Operate (if different from A)	D. Billing Information (if different from A)
23.	Name	Wildflower Energy LP	
24.	Mailing Address	4320 La Jolla Village Dr, Suite 250	
25.	City	San Diego	
26.	State	CA Zip 92122	Zip
27.	Phone	(858) 320 1500 FAX (858) 320 1550	( ) FAX ( )

EQUIPMENT/PROCESS INFORMATION: Check Type of Equipment: ☒ Stationary ☐ Portable - Will operation exceed 180 days: ☐ Yes ☐ No

28. Equipment Location Address Harvest Road and Otay Mesa Road City San Diego Parcel No. See Site Map
29. State CA Zip 92173 Phone ( ) FAX ( )
30. Site Contact To be assigned Title ______ Phone ( )
31. General Description of Equipment/Process 2 Simple Cycle natural gas fired Combustion Gas Turbines, designed to meet local and regional needs for additional Electrical generation during times of peak demand. The plant will be designed to meet SDAPCD BACT requirements.
32. Application Submitted by ☐ Owner ☐ Operator ☐ Contractor ☒ Consultant Affiliation ______

I hereby certify that all information provided on this application is true and correct.

33. SIGNATURE ______ Date ______
34. Print Name ______ Title ______
35. Company ______ Phone ( )

APCD USE ONLY

AP #______ ID #______ Cust. No. ______ Sector:______ UTM's X ______ Y ______ SIC ______
Receipt # ______ Date ______ Amt Rec'd $ ______ Fee Code ______
Engineering Contact ______ Fee Code ______ AP Fee $______ T&M Renewal Fee $______
Refund Claim # ______ Date ______ Amt $______
Application Generated By NV#______ NC #______ Other______ Date______ Inspector______

10/00 - jfq

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION	San Diego APCD Use Only
FEE SCHEDULE 20 A, B, C	Appl. No.:
	ID No.:

GAS TURBINE

(Please type or print the information requested below.)

Company Name: Wildflower Energy LP

Equipment Address: Otay Mesa and Harvest Road, and CIF - Larkspur (ref site map)

A. EQUIPMENT AND PROCESS DESCRIPTION

ENGINE USE: *(Check all that apply.)*

Power Generation: 49,900 kw Steam Generation: n/a lbs/hr steam

Other (Specify capacity.): See BACT evaluation dated 2-23-01 for equipment and process description (Attached for convenience)

ENGINE SPECIFICATIONS:

Manufacturer: General Electric Model No.: LM 6000 Sprint S/N: ________

HP Rating: ________ Fuel Consumption Rate: (see data sheets) 500 mmBtu/hr

1. Type of Liquid Fuel Used*: # 2 oil (natural gas curtailment only)

   Fuel Rate(Specify Units): 420 MMBTU/hr

   Maximum %sulfur by wt. in fuel*: 0.05 %

2. Type of Gaseous Fuel Used*: Natural Gas Fuel Rate:454,411 cfh

   Maximum Grains PM/100DSCF @ 12% O_2: < = 1 grains/100dscf

B. EMISSION CONTROL EQUIPMENT: *(Check all that apply)*

__ Low NOx burner X Water injection

X SCR w/ Ammonia injection __ Hydrogenous X Aqeuous

Describe the control equipment to be installed and submit its technical data:

Reference the BACT regulatory evaluation section submitted with the initial application for Authority to Construct dated 2/23/01 (Application No. 976094).

C. EMISSION DATA SEE ATTACHED EMISSION ESTIMATES FOR WORST CASE LEVELS

Provide the manufacturer's specifications and emission factors (lbs/1,000 lbs of fuel) for oxides of nitrogen (NOx), Carbon monoxide (CO), Hydrocarbons (HC), and particulate matter (PM) for the engine at different power settings with corresponding engine exhaust flow rates and temperatures.

D. EXHAUST STACK AND BLDG. DIMENSIONS *(if air quality modeling is required).*

Stack location: Ground (i.e., roof top, wall, ground), direction: __ vertical __ horizontal

Stack dimensions: internal 12 ft. diameter, or ______ ft. wide x ______ ft. long

Stack dimensions: external 12-6" ft. diameter, or ______ ft. wide x ______ ft. long

(If other shape, then supply sketch of stack cross section)

Use an attached page to provide this information for each engine at each power setting.

Stack height: Above roof: ______ ft. Above ground level: 60 ft.

Site elevation above mean sea level (MSL) 526 ft.

Building dimensions: length __________ ft.; width __________ ft.; height __________ ft.

(Supply sketch w/position of exhaust stack)

Supply a plot plan showing the test cell/stand location with respect to nearby streets, property lines, and buildings.

E. OTHER EMISSION PRODUCING EQUIPMENT AT THE SITE

APCD permitted __ yes X no

Non permitted __ yes X no

F. Additional Information Reference attached project layout for more detailed information. Also, a dimensioned plan and site view of the equipment with manufacturers information will be provided.

G. Operating Schedule:* Hours/day: 24 Days/yr: 365

*Facility will operate 5,950 hours per turbine per year on natural gas only; hours of operation on liquid fuel will reduce hours of operation on gas fuel, accordingly, to be maintained as a non-major stationary source. Permit conditions may result to comply with applicable rules.

Name of Preparer: Shirley Rivera **Title:** Principal

Phone No.: (619) 497 0120 **Date:** __________

NOTE TO APPLICANT:

Before acting on an application for Authority to Construct, Permit to Operate, or Permit to Sell or Rent, the District may require further information, plans, or specifications. Forms with insufficient information may be returned to the applicant for completion, which will cause a delay in application processing and may increase processing fees. The applicant should correspond with equipment and material manufacturers to obtain the information requested on this supplemental form.

EMISSION ESTIMATES

Emission Scenarios
Emission Estimates

MEMORANDUM
March 7, 2001

TO: Wildflower Energy, LP for Larkspur

FROM: Shirley F. Rivera

SUBJECT: **Wildflower Energy, LP, Larkspur**
Modification to Application No. 976094
Emission Scenarios for 2 Turbine Plant

SUMMARY. The following describes the emission scenarios considered for the operation of the Larkspur facility over the life of the project.

- **Turbine make/model:** The initial project is the installation of a GE LM6000 gas turbine rated at not more than 49.9 MW. The second turbine is the installation of a GE LM6000 gas turbine that is identical.

- **Emissions profile:** Each turbine is assumed to have the same emissions profile. These are presented in the emissions estimate tables for one turbine and for two turbines. The information provided by GE are included in the LM6000 data sheet in the emission estimate tables. For worse case assumptions, VOC is assumed to be total hydrocarbons (THC); however, it should be noted that emission rates were provided by GE for 2.0 ppm THC. Worse case emissions on natural gas are based on two runs provided by GE; worse case emissions on distillate are based on one run that had the highest emissions overall. Where emissions were not provided by the vendor for SOx emissions, EPA AP-42 emission factors were assumed. All emissions are based on high heating values.

- **Control technology:** BACT was triggered for NOx, VOC, PM10 and SOx. Both will be equipped with selective catalytic reduction (SCR) to reduce uncontrolled NOx emissions to 5 ppm. Additionally, ammonia slip (NH3) will be limited to not more than 10 ppm. No other controls are proposed. An oxidation catalyst for control of VOC emissions exceed the San Diego APCD's cost-effectiveness benchmark of $7,500/ton of VOC removed. (This demonstration is presented in the BACT evaluation.) VOC will be controlled via good combustion practices. PM10 and SOx emissions will be minimized by the firing of natural gas. Under scenarios of natural gas curtailment, NOx emissions are expected to be not more than 42 ppm.

- **Commissioning / tuning emissions:** During the period of commissioning / tuning, it is estimated that NOx emissions will be uncontrolled at 25 ppm. Other pollutants are expected to be comparable to normal operations.

- **Startup / shutdown emissions:** During normal operations, it is expected that the overall hourly rate during a startup/shutdown of GT1 will meet the hourly emissions expected during normal operations because of the short duration of startup/shutdown necessary for this type of turbine.

Emissions Information. The attachment includes an Excel workbook that contains the emissions related data in support of the expected operations and air quality impact analysis. Below summarizes the content of each excel worksheet.

Page	File	Description
1	Emission Factors_AP-42	Presents EPA AP-42 emission factors for uncontrolled emission rates. EPA emission factors were converted per the project's expected natural gas HHV.
2	LM6000 SPRINT Data	Presents the turbine assumptions, e.g., heat rate, capacity, emission assumptions for gas and distillate. These are the base assumptions for the emission estimates.
3	EMNS_2 GT-NG Only_Controlled	Presents the turbine SCR-controlled NOx emissions (gas) compared to the San Diego APCD regulatory thresholds. Includes hours of operations for normal operations for two turbines.
4	EMNS_2 GT NG Only_Unc	Presents the turbine uncontrolled NOx emissions (gas) compared to the San Diego APCD regulatory thresholds. Includes hours of operations for normal operations for one turbine and for two turbines.
5	EMNS_2GT Oil Only_42 ppm	Presents the turbine uncontrolled NOx emissions (distillate) compared to the San Diego APCD regulatory thresholds. Includes hours of operations for normal operations for two turbines. Represents expected emissions during commissioning/tuning period.
6	Dual Fuel_2GT_SCR_15 hrs Oil	Presents dual fuel turbine operations. Assumes a worse case daily operations of maximum fuel oil (e.g., not more than 16 hrs/day) and remainder on gas (e.g., not more than 8 hrs/day). Annual hours are based on the constraint of not exceeding the major source thresholds.

Summary of Emissions for Air Quality Modeling. Emissions for air quality modeling are based on the hourly rates presented in the emissions estimates, as well as the daily and hourly operations. Each are presented below.

Turbine Specification: The worse-case emissions are based on a turbine with the following specifications: 49,748 kW and 463.50 MMBtu/hr (HHV).

Natural Gas-Firing During Normal Operations and Commissioning / Tuning: Table A presents the following assumptions for air quality modeling purposes of the gas turbines. Unless otherwise noted, hourly emissions are based on GE emissions information and/or emission estimate guidelines.

Table A. Natural Gas-Firing Hourly Emission Rates

	Uncontrolled Emissions, lbs/hr[1]		Controlled Emissions, lbs/hr [2]	
Pollutant	**One Turbine**	**Two Turbine**	**One Turbine**	**Two Turbine**
NOx	42.00	84.00	8.40	16.80
CO	26.81	53.62	26.81	53.62
PM10	3.00	6.00	3.00	6.00
VOC	2.92	5.84	2.92	5.84
SO2[3]	1.58	3.15	1.58	3.15

NOTE: (1) Emissions expected during commissioning / tuning period without SCR.
(2) Emissions expected for normal operations with SCR at 80% control efficiency. Emissions also include startup/shutdown.
(3) SO2 emissions based on EPA AP-42 emission factor.

Distillate Oil-Firing During Natural Gas Curtailment: Table B presents the following assumptions for air quality modeling purposes of the gas turbines during natural gas curtailment. Unless otherwise noted, hourly emissions are based on GE emissions information and/or emission estimate guidelines.

Table B. Distillate Oil-Firing Hourly Emission Rates

	Pollutant Emissions, lbs/hr[1]	
Pollutant	**One Turbine**	**Two Turbine**
NOx	69.00	138.00
CO	15.00	30.00
PM10	12.95	25.90
VOC	5.00	10.00
SO2[2]	13.89	27.78

NOTE: (1) Emissions expected during natural gas curtailment without SCR.
(2) SO2 emissions based on EPA AP-42 emission factor.

Summary of Hours of Operation. The following summarizes the assumptions for turbine operations. Several emission scenarios were considered for the purposes of worse-case air quality modeling impacts. These scenarios are based on a "constraints" analysis, e.g., the maximum hours of operation while maintaining emissions below the major source thresholds.

- **Normal Operations, Two Turbines.** For two turbine operations with SCR controls, not more than 5,950 hrs/yr per turbine are assumed.

- **Commissioning / Tuning Period, One Turbine.** For one turbine operations without SCR controls, not more than 2,380 hrs/tuning are assumed.

- **Commissioning / Tuning Period, Two Turbines.** For two turbine operations without SCR controls, not more than 1,190 hrs/tuning are assumed.

- **Distillate Oil-Firing During Natural Gas Curtailment.** For two turbine operations without SCR controls, daily hours would be limited to 16 hrs/day and 720 hrs per turbine per year.

- **Dual Fuel Firing, Two Turbines.** For two turbine operations on dual fuel in a given day, daily hours were assumed to be not more than 16 hrs/day (oil) as a worse-case with the remaining 8 hrs/day (gas). Annual hours on oil are assumed at 225 hrs/yr and on gas are assumed at 4,100 hrs/yr.

Where hours presented in the modeling may be higher, this is to account for the "constraints" analysis approach.

Commissioning / Tuning Period. For the purposes of worse-case emissions, the maximum hours were estimated as if one turbine or two turbines are undergoing commissioning. The worse-case is if two turbines are undergoing commissioning concurrently which is not expected for the project operations. That said, hours of operation were determined that resulted in staying below the major source thresholds for both the one-turbine and two-turbine case. It is not expected that the commissioning period would ever exceed a total of 1,190 hours (e.g., more than a month, approximately 45 days assuming 24 hrs/day for commissioning) for the tuning period. Again, it is not expected that commissioning would be "around-the-clock" and therefore the 24 hrs/day is a worse-case estimate. However, air quality modeling for the lb/day impacts were based on this 24 hrs/day scenario for worse-case impacts.

Compliance Demonstration Condition: Total facility emissions will be no greater than the major source thresholds.

Annual: $[(\text{mass, lb/hr})*(\text{hours})/2000]_{\text{GAS TURBINE 1 (GAS)}} +$
$[(\text{mass, lb/hr})*(\text{hours})/2000]_{\text{GAS TURBINE 1 (OIL)}} +$
$[(\text{mass, lb/hr})*(\text{hours})/2000]_{\text{GAS TURBINE 2 (GAS)}} +$
$[(\text{mass, lb/hr})*(\text{hours})/2000]_{\text{GAS TURBINE 2 (OIL)}}$
$=$ total tons

Hours of operation for each turbine will be monitored and recorded. Emissions associated with hours of operation will be calculated to ensure total facility emissions remain below the San Diego APCD major source thresholds presented in Table C.

Table C. San Diego APCD Major Source Thresholds

Pollutant	Threshold, tons/year
NOx	50
CO	250
PM10	100
VOC	50
SO2	100

Emissions will be monitored via continuous emissions monitoring equipment. Emissions will be determined as follows:

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Wildflower Energy, LP - Larkspur
SDAPCD Application No. 976094

EPA AP-42 Emission Factors

Assume: HHV = 1.106 * LHV Natural Gas
HHV = 1.06 *LHV Distillate

Natural Gas Uncontrolled Emission Factors

Pollutant		Comments	EPA Rating	Pollutant	lb/MMBtu
NOx	0.32 lb/MMBtu		A	NOx	0.33
CO	0.082 lb/MMBtu		A	CO	0.084
PM10	0.0066 lb/MMBtu	Total PM10 based on water-steam injection	C	PM10	0.0068
TOC	0.011 lb/MMBtu	Based on EPA Test Method 25A	B	TOC	0.011
VOC	0.0021 lb/MMBtu		D	VOC	0.0022
SO2	0.0034 lb/MMBtu	Default value (or use 0.94*S)	B	SO2	0.0035

All Natural Gas HHV 1020 Btu/scf
All at Operating load ≥ 80%

Natural Gas HHV 1047 Btu/scf
(from GE S&WES information)

Distillate Uncontrolled Emission Factors

Pollutant		Comments	EPA Rating	Pollutant	lb/MMBtu
NOx	0.88 lb/MMBtu		C	NOx	0.871
CO	0.0033 lb/MMBtu		C	CO	0.0033
PM10	0.012 lb/MMBtu	Total PM10 based on water-steam injection	C	PM10	0.012
TOC	0.004 lb/MMBtu	Based on EPA Test Method 25A; water inj	C	TOC	0.004
VOC	0.00041 lb/MMBtu	Equal to sum of organic emissions	E	VOC	0.00041
SO2	0.033 lb/MMBtu	Default value (or use 1.01*S)	B	SO2	0.033

All Distillate average heating value 139 MMBtu/ 1000 gallons fuel oil
All at Operating load ≥ 80%

Distillate density: 7.05 lbs/gal
Maximum %S content: 0.05% wt

Distillate LHV 18400 Btu/lb
Distillate HHV 19504 Btu/lb
Distillate HHV 138 MMBtu/1000 gal

Wildflower Energy, LP - Larkspur
SDAPCD Application No. 976094

LM6000 SPRINT DATA

CASE 1G: Natural Gas; Min Temp (100%)
CASE 3G: Natural Gas; Base (100%)
CASE 202D: Distillate; Evap-On (mid temp at 83 deg F)
CASE 204D: Distillate; Evap-On (lower temp at 70 deg F)
CASE 206D: Distillate; Evap-On (mid temp at 80 deg F)
CASE 208D: Distillate; Evap-On (hi temp at 90 deg F)

Assume:				
	HHV =	1.106	* LHV	Natural Gas
	HHV =	1.06	*LHV	Distillate
	Natural Gas:	20,996	Btu/lb (HHV)	
	Distillate:	18400	Btu/lb (LHV)	19504 Btu/lb (HHV)

Characteristics:	**CASE 1G**	**CASE 3G**	**CASE 202D**	**CASE 204D**	**CASE 206D**	**CASE 208D**
Amb DB Temp (F)	18	60	83	70	80	90
kW (Output)	49,748	47,394	42,703	44,701	43,200	39,845
Btu/kW-hr (LHV)	8,424	8,690	8,966	8,884	8,947	9,076
MMBtu/hr, LHV	419.08	411.85	382.88	397.12	386.51	361.63
MMBtu/hr, HHV	463.50	455.51	405.85	420.95	409.70	383.33
Fuel flow, lbs/hr	22076	21695	20808	21583	21006	19654

Emission Factor:

SOx (gas)	0.0034	lb/MMBtu (AP-42, Fifth Edition, Supplement F)
SOx (distillate)	0.033	lb/MMBtu (AP-42, Fifth Edition, Supplement F)
PM10 (distillate)	0.6	*(fuel flow, lbs/hr) divided by 1000

Uncontrolled Emissions, lbs/hr

POLLUTANT	**CASE 1G**	**CASE 3G**	**CASE 202D**	**CASE 204D**	**CASE 206D**	**CASE 208D**
NOx*	42.00	41.61	66.00	69.00	67.00	63.00
CO*	59.00	26.81	6.00	6.00	6.00	6.00
PM10	3.00	3.00	12.49	12.95	12.60	11.79
HC*	1.00	1.66	1.00	1.00	1.00	1.00
SO2	1.58	1.55	13.39	13.89	13.52	12.65
CO**	59.00	26.81	15.00	15.00	15.00	15.00
VOC*** (TOC)	11.68	11.64	5.00	5.00	5.00	5.00
VOC****	2.92	2.91	1.25	1.25	1.25	1.25

Note: * Based on S&WES info from GE
** Based on S&WES info from CE; maximum CO emissions
*** Based on GE recommending use of THC for VOC estimate.
**** VOC is approximately 25% of TOC (per EPA AP-42, non-methane).

WORST CASE EMISSIONS BASED ON CASE 1G and 3G VALUES

Assume:	49,748	kw	Turbine output		
	8,424	Btu/kW-hr	Heat rate (LHV)		
	419.1	MMBtu/hr, LHV		**Assume:**	
	463.5	MMBtu/hr, HHV		HHV =	1.106 * LHV

POLLUTANT CONTROL ASSUMPTIONS

NOx Control efficiency:	80%	[SCR; Control efficiency guarantee]
CO Control efficiency:	0%	[CO does not trigger BACT.]
VOC (THC) Control efficiency:	0%	[Oxidation catalyst is not cost-effective.]

Per Turbine Pollutant	Uncontrolled lb/hr	Controlled lb/hr	NOTES
NOx	42.00	8.40	Case 1G; Control from 25 ppm to 5 ppm.
CO	26.81	26.81	Based on CASE 3G
PM10	3.00	3.00	Based on GE emissions guidelines.
VOC	2.92	2.92	Based on CASE 1G; VOC is 25% TOC
SO2	1.58	1.58	EPA AP-42, Fifth Edition, Supplement F; Case 1G

NSR PERMIT THRESHOLDS
TRIGGER LEVELS: Rule 20.1, et. al relevant trigger levels for permitting.

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	25	250	40	10	50	50
CO	100	550	100	NA	250	NA
PM10	---	100	15	10	100	NA
VOC	NA	NA	NA	10	50	50
SO2	25	250	40	10	100	NA

Both Turbines

EMISSION ESTIMATES: 24 hrs/day 5950 hrs/year

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	16.80	403.20	49.98	403.20	49.98	49.98
CO	53.62	1,286.88	159.52	1,286.88	159.52	159.52
PM10	6.00	144.00	17.85	144.00	17.85	17.85
VOC	5.84	140.16	17.37	140.16	17.37	17.37
SO2	3.15	75.64	9.38	75.64	9.38	9.38

REGULATORY REQUIREMENT TRIGGERED?

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	No	Yes	Yes	Yes	No	No
CO	No	Yes	Yes	NA	No	NA
PM10	NA	Yes	Yes	Yes	No	*
VOC	NA	NA	NA	Yes	No	No
SO2	No	No	No	Yes	No	NA

* *Dependent on AQIA modeling results*

Wildflower Energy, LP - Larkspur
SDAPCD Application No. 976094

WORST CASE EMISSIONS BASED ON CASE 1G and 3G VALUES

Assume:	49,748	kw	Turbine output		
	8,424	Btu/kW-hr	Heat rate (LHV)		
	419.1	MMBtu/hr, LHV		**Assume:**	
	463.5	MMBtu/hr, HHV		HHV =	1.106 * LHV

POLLUTANT CONTROL ASSUMPTIONS

NOx Control efficiency:	0%	[SCR; Control efficiency guarantee]
CO Control efficiency:	0%	[CO does not trigger BACT.]
VOC (THC) Control efficiency:	0%	[Oxidation catalyst is not cost-effective.]

Pollutant	Uncontrolled lb/hr	Controlled lb/hr	NOTES
NOx	42.00	42.00	Case 1G; Control from 25 ppm to 5 ppm.
CO	26.81	26.81	Based on CASE 3G
PM10	3.00	3.00	Based on GE emissions guidelines.
VOC	2.92	2.92	Based on CASE 1G; VOC is 25% TOC
SO2	1.58	1.58	EPA AP-42, Fifth Edition, Supplement F; Case 1G

NSR PERMIT THRESHOLDS
TRIGGER LEVELS: Rule 20.1, et. al relevant trigger levels for permitting.

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	25	250	40	10	50	50
CO	100	550	100	NA	250	NA
PM10	---	100	15	10	100	NA
VOC	NA	NA	NA	10	50	50
SO2	25	250	40	10	100	NA

ONE TURBINE

EMISSION ESTIMATES: 24 hrs/day 2380 hrs/year

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	42.00	1,008.00	49.98	1,008.00	49.98	49.98
CO	26.81	643.44	31.90	643.44	31.90	31.90
PM10	3.00	72.00	3.57	72.00	3.57	3.57
VOC	2.92	70.08	3.47	70.08	3.47	3.47
SO2	1.58	37.82	1.88	37.82	1.88	1.88

TWO TURBINE

EMISSION ESTIMATES: 24 hrs/day 1190 hrs/year

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	84.00	2,016.00	49.98	2,016.00	49.98	49.98
CO	53.62	1,286.88	31.90	1,286.88	31.90	31.90
PM10	6.00	144.00	3.57	144.00	3.57	3.57
VOC	5.84	140.16	3.47	140.16	3.47	3.47
SO2	3.15	75.64	1.88	75.64	1.88	1.88

Wildflower Energy, LP - Larkspur
SDAPCD Application No. 976094

WORST CASE EMISSIONS BASED ON CASE 204D

Assume:	44,701	kw	Turbine output		
	8,884	Btu/kW-hr	Heat rate		
	397.1	MMBtu/hr, LHV		**Assume:**	
	421.0	MMBtu/hr, HHV		HHV =	1.06 * LHV

POLLUTANT CONTROL ASSUMPTIONS

NOx Control efficiency:	0%	[Based on 42 ppm NOx]
CO Control efficiency:	0%	[CO does not trigger BACT.]
VOC (THC) Control efficiency:	0%	[Oxidation catalyst is not cost-effective.]

Per Turbine Pollutant	Uncontrolled lb/hr	Controlled lb/hr	NOTES
NOx	69.00	69.00	SCR on-line.
CO	15.00	15.00	Worst-case CO emissions.
PM10	12.95	12.95	Based on GE emissions guidelines (01/16 e-mail)
VOC (THC)	5.00	5.00	Based on GE emissions guidelines.
SO2	13.89	13.89	EPA AP-42, Fifth Edition, Supplement F

NSR PERMIT THRESHOLDS
TRIGGER LEVELS: Rule 20.1, et. al relevant trigger levels for permitting.

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	25	250	40	10	50	50
CO	100	550	100	NA	250	NA
PM10	---	100	15	10	100	NA
VOC	NA	NA	NA	10	50	50
SO2	25	250	40	10	100	NA

2 Turbines

EMISSION ESTIMATES: 16 hrs/day 720 hrs/turbine/year

Pollutant	AQIA (lb/hr)	16 (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	138.00	2,208.00	49.68	2,208.00	49.68	49.68
CO	30.00	480.00	10.80	480.00	10.80	10.80
PM10	25.90	414.39	9.32	414.39	9.32	9.32
VOC	10.00	160.00	3.60	160.00	3.60	3.60
SO2	27.78	444.52	10.00	444.52	10.00	10.00

REGULATORY REQUIREMENT TRIGGERED?

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	Yes	Yes	Yes	Yes	No	No
CO	No	No	No	NA	No	NA
PM10	NA	Yes	No	Yes	No	*
VOC	NA	NA	NA	Yes	No	No
SO2	Yes	Yes	No	Yes	No	NA

** Dependent on AQIA modeling results*

version: 03/05/01

Wildflower Energy, LP - Larkspur
SDAPCD Application No. 976094

GAS Per Turbine **WORST CASE EMISSIONS BASED ON CASE 1G and 3G VALUES**

Assume:

49748	kw	Turbine output		
8424	Btu/kW-hr	Heat rate (LHV)		
419.1	MMBtu/hr, LHV		**Assume:**	
463.5	MMBtu/hr, HHV		HHV =	1.106 * LHV

POLLUTANT CONTROL ASSUMPTIONS

NOx	Control efficiency:	80%	[SCR; Control efficiency guarantee]
CO	Control efficiency:	0%	[CO does not trigger BACT.]
VOC (THC)	Control efficiency:	0%	[Oxidation catalyst is not cost-effective.]

Pollutant	Uncontroll lb/hr	Controlled lb/hr	NOTES
NOx	42.00	8.40	Case 1G; Control from 25 ppm to 5 ppm.
CO	26.81	26.81	Based on CASE 3G
PM10	3.00	3.00	Based on GE emissions guidelines.
VOC	2.92	2.92	Based on CASE 1G; VOC is 25% TOC
SO2	1.58	1.58	EPA AP-42, Fifth Edition, Supplement F; Case 1G

OIL Per Turbine **WORST CASE EMISSIONS BASED ON CASE 204D**

Assume:

44701	kw	Turbine output		
8884	Btu/kW-hr	Heat rate		
397.1	MMBtu/hr, LHV		**Assume:**	
421.0	MMBtu/hr, HHV		HHV =	1.06 * LHV

POLLUTANT CONTROL ASSUMPTIONS

NOx	Control efficiency:	0%	[Based on 42 ppm NOx]
CO	Control efficiency:	0%	[CO does not trigger BACT.]
VOC (THC)	Control efficiency:	0%	[Oxidation catalyst is not cost-effective.]

Pollutant	lb/hr	lb/hr	NOTES
NOx	69.0	69.0	Uncontrolled
CO	15.0	15.0	Worst-case CO emissions.
PM10	12.9	12.9	Based on GE emissions guidelines (01/16 e-mail)
VOC (THC)	5.0	5.0	Based on GE emissions guidelines.
SO2	13.9	13.9	EPA AP-42, Fifth Edition, Supplement F

Both Turbines
EMISSION ESTIMATES:

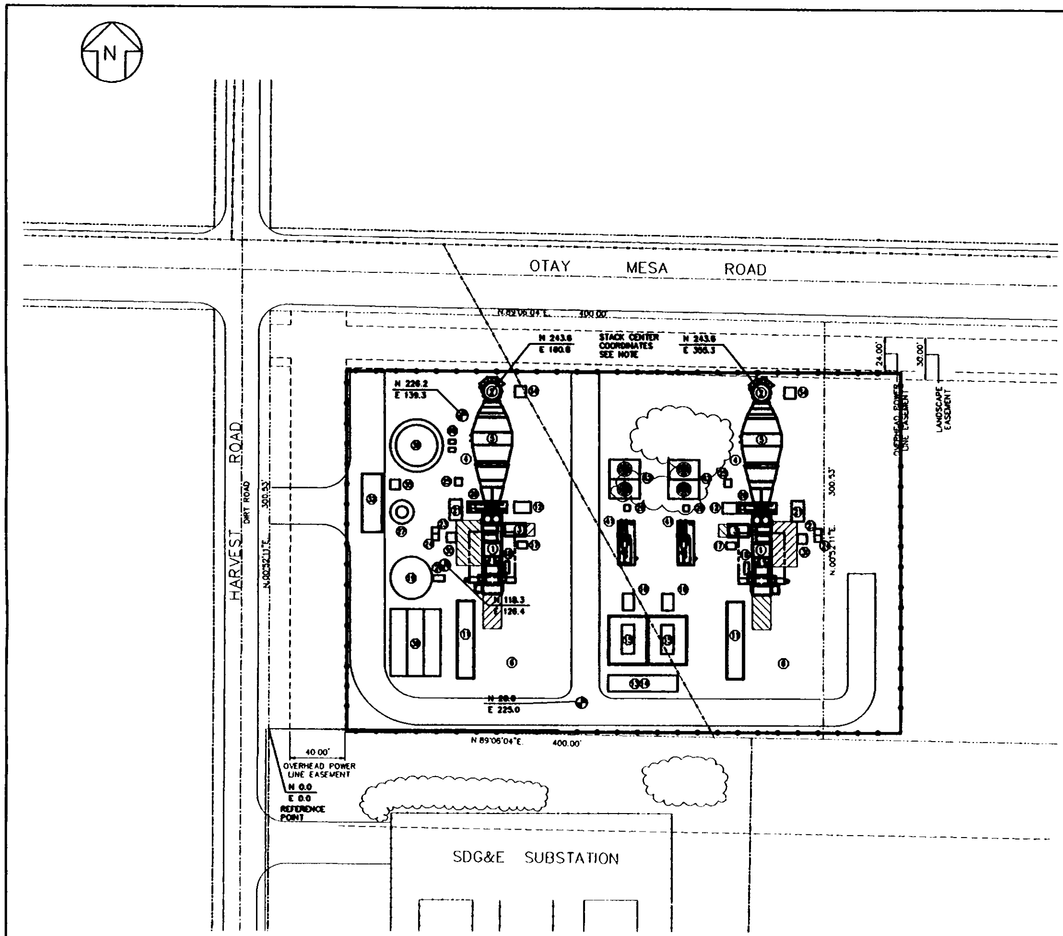
Gas Firing:	8	hrs/day	4100	hrs/year
Oil Firing:	16	hrs/day	225	hrs/year
Total:	24	hrs/day	4325	hrs/year
Check oper hours:	**okay**		**okay**	

Pollutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	assume a worst case on oil and a worse case on gas	2342.40	49.97	2342.40	49.97	49.97
CO		908.96	113.30	908.96	113.30	113.30
PM10		462.39	15.21	462.39	15.21	15.21
VOC		206.72	13.10	206.72	13.10	13.10
SO2		469.74	9.59	469.74	9.59	9.59

REGULATORY REQUIREMENT TRIGGERED?

Poilutant	AQIA (lb/hr)	AQIA (lb/day)	AQIA (tons/yr)	BACT (lb/day)	Major Source (tons/yr)	Offsets (tons/yr)
NOx	assume a worst case on oil and a worse case on gas	Yes	Yes	Yes	No	No
CO		Yes	Yes	NA	No	NA
PM10		Yes	Yes	Yes	No	No
VOC		No	No	Yes	No	No
SO2		Yes	No	Yes	No	No

SITE LAYOUT



LEGEND			
ITEM	DESCRIPTION	QTY	NOTE
1	GAS TURBINE GENERATOR (RIGHT HAND)	1	
2	EXHAUST STACK	1	
3	AUXILIARY SKID	1	
4	SCR ENCLOSURE (TURNED)	1	
5	CO CATALYST BED/NOx CATALYST BED	1	
6	HIGH VOLTAGE SUBSTATION	1	
7	MEDIUM VOLTAGE SWITCHGEAR	1	
8	MAIN SUBSTATION STEP-UP TRANSFORMER	1	
9	AUX TRANSFORMER (13.8 KV / 480V)	1	
10	COMPRESSOR TRANSFORMER (13.8 KV / 4.16KV)	1	
11	MODULAR CONTROL ROOM	1	
12	AIR COMPRESSOR SKID	1	
13	FUEL GAS METER	1	
14	FUEL GAS BLOCK VALVE	1	
15	FUEL GAS COMPRESSOR / SCRUBBER	1	1 X 100%
16	FUEL GAS AIR COOLER	1	
17	FUEL GAS FILTER	1	1 X 100%
18	CO2 BOTTLE CABINET	1	
19	DEMINERALIZED WATER STORAGE TANK	1	110,000 GAL.
20	WATER INJECTION FORWARDING PUMP	1	1 X 100%
21	WATER INJECTION PUMP SKID	1	
22	NOT USED	1	
23	OIL/WATER SEPARATOR	1	
24	OIL/WATER SEPARATOR PUMPS	2	
25	WASTE SUMPS	2	
26	SAFETY FENCE	1	
27	AMMONIA STORAGE TANK	1	
28	AMMONIA INJECTION SKID	1	
29	CT FEED	1	
30	LUBE OIL AIR COOLER	1	
31	NOT USED	1	
32	AQUEOUS AMMONIA AND FUEL OIL UNLOADING AREA	1	
33	BREAKER	1	
34	CEMS HOUSING	1	
35	FUEL OIL UNLOADING PUMPS	1	
36	PORTABLE TRAILER PARKING	2	
37	NOT USED	1	
38	NOT USED	2	
39	DIESEL STORAGE TANK	1	110,000 GAL.
40	DIESEL PUMPS	2	
41	CHILLER PACKAGE	1	
42	COOLING TOWER	1	

LEGEND:

PROPERTY LINE
EASEMENT LINE
EXISTING GAS LINE
EXISTING ROAD
EXISTING TREES
BORING LOCATION SEE NOTE 2

0 30 60 FEET
GRAPHIC SCALE

NOTES:

1. THE STACK CENTER COORDINATES SHOWN HEREIN ARE LOCAL TO THE SITE PROPERTY AND WHERE ESTABLISHED FROM THE IDENTIFIED REFERENCE POINT ALONG THE PROPERTY LINE. THE LOCAL COORDINATES NEED TO BE CONVERTED TO GLOBAL USGS COORDINATE SYSTEM FOLLOWING RECEIPT OF THE FIELD SURVEY DATA.

2. STACK LOCATION ON THE SITE IS BASED ON THE BEST AVAILABLE VENDOR AND SITE INFORMATION. THE LAYOUT WILL BE OPTIMIZED AS ADDITIONAL INFORMATION BECOMES AVAILABLE. THE EFFECT ON STACK LOCATION CAN NOT BE DETERMINED AT THIS TIME. HOWEVER EFFORT WILL BE MADE TO KEEP STACK LOCATION AS SHOWN.

3. CONTRACTOR SHALL FIELD VERIFY THE LOCATION OF ALL UNDERGROUND UTILITIES PRIOR TO DRILLING ACTIVITIES.

REV.	DATE	DESCRIPTION
A	[illegible]	ISSUED FOR CLIENT REVIEW

R.G. Vanderweil Engineers, Inc.
274 Summer Street - Boston, MA 02210
(617) 423-7423

RGV Job No. | Sheet 1 of 1
Drawn by: [illegible]
Checked by: [illegible]
Date of Original: [illegible]
Scale: 1"=30'-0"

Project
GEMMA POWER SYSTEMS
WILDFLOWER PROJECT

Title
GENERAL ARRANGEMENT
SITE PLAN
BORDER I

M-101B

Air Quality Impact Analysis and Rule 1200 Evaluation

Prepared for:

Wildflower Energy, LP
Larkspur Site

WILDFLOWER
ENERGY

INTERGEN

SRA Scientific Resources Associated
927 Wilbur, Suite 1
San Diego, CA 92109

Table of Contents

1.0 INTRODUCTION

As described in the transmittal letter, Wildflower Energy, LP is proposing to construct a second GE LM 6000 PC Sprint simple-cycle, natural gas-fired turbine at the Larkspur site on Otay Mesa near the U.S.-Mexican Border. The site will be located at the corner of Otay Mesa Road and Harvest Road, just north of the San Diego Gas & Electric Border Substation. The second turbine will be identical to the initial turbine proposed for the site. This section presents an update to the AQIA and Rule 1200 evaluations, as well as select original assumptions, that were submitted with the initial application for Authority to Construct on February 23, 2001. The revised AQIA and Rule 1200 evaluations are based on the assumption that the combined NOx emissions from both turbines will not exceed 50 tons per year, and that the combined emissions of other criteria pollutants will also be below the major source thresholds for those pollutants. The purpose of the new gas turbines will be to generate electricity for sale on the California Independent System Operator (Cal-ISO) grid.

According to Rule 20.2, New Source Review, an AQIA is required for new or modified facilities that result in an emissions increase above the AQIA trigger levels in Table 20.2-1, as shown below:

Table 1
Rule 20.2
AQIA Trigger Levels

	Trigger Levels		
Air Contaminant	lb/hr	lb/day	tons/yr
Particulate Matter (PM10)	--	100	15
Oxides of Nitrogen (NOx)	25	250	40
Oxides of Sulfur (SOx)	25	250	40
Carbon Monoxide (CO)	100	550	100
Lead and Lead Compounds	--	3.2	0.6

It was assumed that the SCR will control NOx emissions to no more than 5 ppm at 15% O_2. In addition, natural gas firing and efficient combustion practices will be used to minimize PM10, SOx, and VOC emissions. Both units will also have the capability of firing on distillate fuel oil during natural gas curtailment episodes.

Based on these assumptions for the emission estimates, an AQIA is triggered for CO and for uncontrolled NOx emissions during commissioning prior to SCR operation when the unit is fired on natural gas. An AQIA is triggered for NOx, CO, and PM10 when fired with fuel oil during natural gas curtailment episodes. In the event of a natural gas curtailment, the facility would adjust the annual hours of operation to ensure that the NOx emissions would not exceed 50 tons per year, and that the major source thresholds for other criteria pollutants would not be exceeded. To address the potential impacts associated with fuel oil firing, an operational scenario assuming a maximum daily operation on fuel oil of 16 hours per day and a maximum annual operation on fuel oil for both turbines combined of 225 hours per year was evaluated. The emission estimates are shown in Table 2 below.

Table 2
Emission Estimates
GE LM 6000 PC Sprint – 2 Turbines

Air Contaminant	Emissions lb/hr	lb/day	tons/yr	AQIA Triggered?
Natural Gas				
Particulate Matter (PM10)	6.00	144.00	17.85	Yes
Oxides of Nitrogen (NOx) (controlled)	16.80	403.20	49.98	No
Oxides of Nitrogen (NOx) (uncontrolled)	84.00	2,016.00	49.98	Yes
Oxides of Sulfur (SOx)	3.15	75.64	9.38	No
Carbon Monoxide (CO)	53.62	1,286.88	159.52	Yes
Lead and Lead Compounds	N/A	N/A	N/A	N/A
Fuel Oil Scenario (16 hrs/day, 225 hrs/yr on Fuel Oil), both turbines				
Particulate Matter (PM10)	25.9[1]	462	15.2	Yes
Oxides of Nitrogen (NOx)	69[1]	2,342	49.97	Yes
Oxides of Sulfur (SOx)	27.8[1]	470	9.6	No
Carbon Monoxide (CO)	53.62[2]	909	113.3	Yes
Lead and Lead Compounds	N/A	N/A	N/A	N/A

[1]Hourly emissions for fuel oil
[2]Hourly emissions for natural gas

Because the requirement for an AQIA is triggered for NOx and CO emissions under an uncontrolled operational scenario and for NOx, CO, and PM10 under the fuel oil operational scenario, an AQIA has been performed for NO_2, CO, and PM10 to demonstrate that the proposed project will not:

(A) cause a violation of a state or national ambient air quality standard anywhere that does not already exceed such standard, nor

(B) cause additional violations of a national ambient air quality standard anywhere the standard is already being exceeded, nor

(C) cause additional violations of a state ambient air quality standard anywhere the standard is already being exceeded, except as provided for in Subsection (d)(2)(v), nor

(D) prevent or interfere with the attainment or maintenance of any state or national ambient air quality standard.

The relevant ambient air quality standards are shown in Table 3 below.

Table 3

Ambient Air Quality Standards

Pollutant	Averaging Time	CAAQS	NAAQS Primary	NAAQS Secondary
O_3	1 Hour	180	235	235
CO	8 Hour	10,000	10,000	
	1 Hour	23,000	40,000	
NO_2	Annual Average		100	100
	1 Hour	470		
SO_2	Annual Average		80	
	24 Hour	105	365	
	3 Hour			1,300
	1 Hour	655		
PM_{10}	Annual Geometric Mean	30		
	24 Hour	50	150	150
	Annual Arithmetic Mean		50	50
Sulfates	24 Hour	25		
Pb	30-Day Average	1.5		
	Calendar Quarter		1.5	1.5
Hydrogen Sulfide	1 Hour	42		
Vinyl Chloride	24 Hour	26		
Visibility Reducing Particles	8 Hour	Extinction Coefficient > 0.23 per kilometer		

In addition to conducting an AQIA, in accordance with the requirements of San Diego APCD Rule 1200, the facility must demonstrate that the increase in maximum incremental cancer risk at every receptor location is equal to or less than one in one million for any project for which new, relocated, or modified emission units that increases maximum incremental cancer risk are not equipped with T-BACT; or the increase in maximum incremental cancer risk at every receptor location is equal to or less than ten in one million provided the emission units are equipped with T-BACT. Furthermore, the provisions of Rule 1200 require that the increase in the total acute noncancer health hazard index at every receptor must be equal to or less than one, and that the total chronic noncancer health hazard index at every receptor must be equal to or less than one, unless the Air Pollution Control Officer determines than an alternate total hazard index is sufficiently health protective.

2.0 BACKGROUND AMBIENT AIR QUALITY

The following presents the background ambient air quality and attainment status with regard to NO_2, CO and PM10; the meteorological data and a discussion of its representativeness for the Larkspur site; the results of the ambient air quality analysis, including a discussion of the approach in conducting the analysis; and the results of the Rule 1200 health risk analysis.

According to the requirements for conducting an AQIA, the initial step is to ascertain the existing background ambient air quality for the pollutants that are to be considered in the AQIA. The nearest monitoring station to the Larkspur facility is the Otay Mesa-Paseo International station located at Otay Mesa. Table 4 presents the NO_2, CO, and PM10 background ambient air quality for 1996-1999 for this monitoring station.

Table 4
Highest Background Ambient Air Quality
(micrograms/cubic meter)

Monitoring Station	1996	1997	1998	1999	CAAQS	NAAQS
Nitrogen Dioxide						
1-Hour						
Otay Mesa		200.9	247.8	322.9	470	N/A
Annual Average						
Otay Mesa		41.3	41.3	43.2	N/A	100
Carbon Dioxide						
1-Hour						
Otay Mesa	13,714	9,143	5,714		23,000	40,000
8-Hour						
Otay Mesa		5,291	4,514	5,634	10,000	10,000
PM10						
24-Hour						
Otay Mesa		125	89	121	470	N/A
Annual Average – Geometric Mean[1]						
Otay Mesa		41.9	38.6	47.5	N/A	100
Annual Average – Arithmetic Mean[1]						
Otay Mesa		46.6	42.8	52.1	N/A	100

[1]The CAAQS is based on the annual geometric mean; the NAAQS is based on the annual arithmetic mean.

The Otay Mesa monitoring station represents a highly conservative estimate of background ambient air quality because of the station's location at the border crossing at Otay Mesa and its influence from vehicular traffic.

The background ambient air quality data indicate that the San Diego Air Basin is currently attaining the National Ambient Air Quality Standards NAAQS) and the California Ambient Air Quality Standards (CAAQS) for NO_2 and CO. The Otay Mesa monitoring station data indicates that the annual and 24-hour CAAQS for PM10 are exceeded. There is only one county in California that has not experienced exceedances of the CAAQS for PM10. The San Diego Air Basin is in attainment of the NAAQS for PM10.

3.0 METEOROLOGICAL DATA

The Larkspur site is located on an undeveloped site at the corner of Otay Mesa Road and Harvest Road in Otay Mesa. The climate of the site, and all of San Diego, is dominated by a semi-permanent high pressure cell located over the Pacific Ocean. This cell influences the direction of prevailing winds (westerly to northwesterly) and maintains clear skies for much of the year. Because of the site's inland location, surface meteorological data collected at the Marine Corps Air Station (MCAS) Miramar site were used to conduct the air quality impact analysis. Upper air data from MCAS Miramar were used for the mixing height, as Miramar is the closest upper air station at which mixing heights are measured.

Figure 1 presents a wind rose from MCAS Miramar. The wind rose indicates the general wind direction at the site. Three sequential years of meteorological data (1992 through 1994) were used in the air dispersion modeling. Because the meteorological data do not vary substantially from year to year, the data were considered to be representative of meteorological conditions at the site.

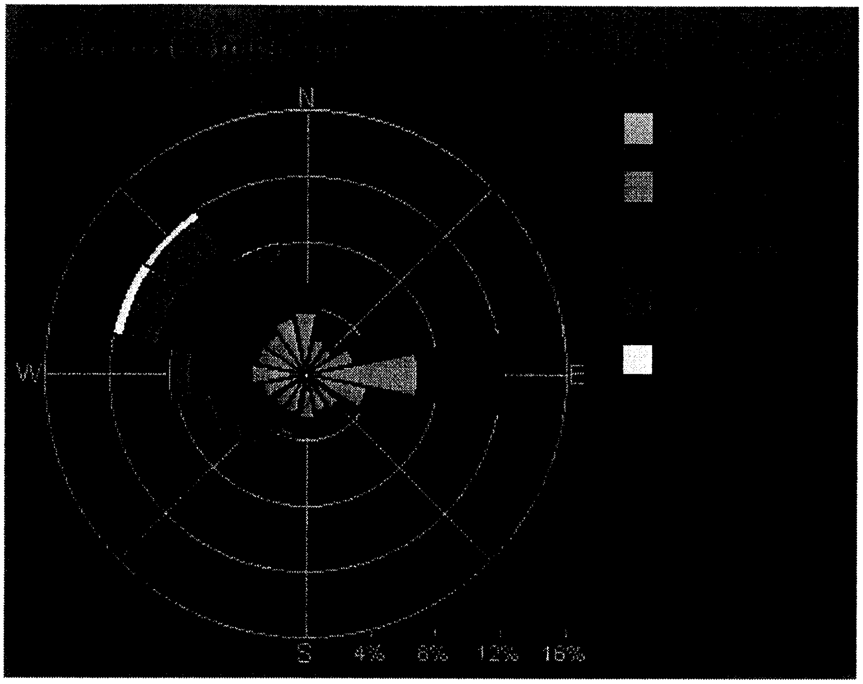


Figure 1. Wind Rose – MCAS Miramar

The following represents an update of the AQIA and Rule 1200 analysis (that originally was performed for one turbine at the Larkspur site) to account for two turbines operating at the site. The background ambient air quality data, meteorological data, and toxicological data used to conduct the AQIA and Rule 1200 evaluations did not change from the original analysis and are previously presented in this analysis. Also, the stack parameters and downwash evaluation for the second turbine are the same as for the first turbine and are presented below in Table 5.

Table 5 presents the stack parameters for the GE LM 6000 PC Sprint with Turner SCR that were used in the AQIA, and the modeling parameters for the proposed project.

Table 5
Stack Parameters
Larkspur Facility

Parameter	Value
Average High Heating Value of Fuel	1,020 BTU/SCF
Stack Height	60 feet
Stack Diameter	12 feet
Stack Exit Temperature	850 F
Stack Exit Volumetric Flow	550920 ACFM
Stack Exit Velocity	88.4 ft/s

Additional specifics regarding turbine specifications and emissions are detailed in the emission estimates section of this permit application.

The Industrial Source Complex Short Term 3 (ISCST3) model, version 10100, was used for the AQIA. The ISCST3 model receptor grid was set up as follows: 50-meter spacing along the property boundary and from the facility boundary to 200-meter distance; 100-meter spacing from 200 meters to 1 kilometer; and 200-meter spacing from 1 kilometer to 5 kilometers. The receptor grid was sufficiently large to include areas of high terrain, including higher elevations west of the site. In addition, a 50-meter grid was sited where the initial modeling effort indicated the maximum impacts would be predicted.

Table 6 presents the ISCST3 model option settings that were used in the modeling effort.

Table 6
ISCST3 Model Option Settings

Model Option	Setting
Model Calculates	Concentration
Receptor Grid System	Cartesian
Terrain Elevations Read	Yes
Calm Processing Used	Yes
Dispersion Coefficients	Rural
Stack Tip Downwash	Yes
Gradual Plume Rise	Yes
Buoyancy-Induced Dispersion	Yes
Wind Profile Exponent Values	Default
Vertical Potential Temperature Gradient	Default
Building Downwash	Included

Because the site is located in an undeveloped area, rural dispersion coefficients were appropriate for the proposed facility.

Building downwash was taken into account using the USEPA's BPIP model (USEPA 1995) which is the most recent version of the building downwash model available. In accordance with USEPA guidelines, building downwash must be considered if the stack heights are less than "Good Engineering Practice" (GEP) heights. GEP heights can be calculated by the following equation:

$$H_s = H_b + 1.5L$$

Where

H_s = GEP stack height
H_b = building height
L = lowest of building height, width, or length

The GEP formula indicates whether emissions from a stack will be affected by downwash associated with nearby buildings. Building dimensions were obtained from the existing facility, surrounding buildings, and GE information regarding the turbine housing and configuration. The facility location is shown in Figure 2. The proposed minimum stack height of 60 feet is below the GEP stack height, and building downwash must be considered.

In accordance with USEPA guidelines, all buildings within 5L should be included in the building downwash modeling, where L = the lesser of the building width and length.

Because the SCR housing would dominate any downwash effects expected, the SCR housing was the only structure that was included in the modeling analysis. The other structures on or near the stack would be small support structures that would not exceed 1 story in height. The SCR housing was assumed to be a rectangular structure with dimensions 32 ft. wide X 89 ft. long X 40 ft. high.

4.0 AIR QUALITY IMPACT ANALYSIS MODEL RESULTS

This section presents the results of the AQIA for NO_2, CO, and PM10 as required under Rule 20.2.

To evaluate compliance with the ambient air quality standards, NO_2 impacts were modeled for 1-hour and annual averaging times. CO impacts were modeled for 1-hour and 8-hour averaging times. PM10 impacts were modeled for 24-hour and annual averaging time. The fuel oil operational scenario was modeled based on firing each turbine with fuel oil for a maximum of 16 hours per day, 225 hours per year.

Table 7 presents the results of the AQIA. The predicted concentrations that occurred at the maximum point of impact from both turbines were added to the highest ambient background concentrations to obtain an estimate of the worst-case maximum impacts.

Table 7
AQIA Modeling Results
$\mu g/m^3$

Pollutant	Averaging Time	Maximum Predicted Impact, Turbine 1[1]	Maximum Predicted Impact, Turbine 2[1]	Impact + Background[2]	NAAQS	CAAQS
Uncontrolled - Natural Gas						
NO_2	Annual	0.055	0.056	43.3	100	
	1 Hour	25.65	26.07	374.6		470
CO	8 Hour	11.2	11.4	5,657	10,000	10,000
	1 Hour[3]	21.8	22.2	13,758	40,000	23,000
Fuel Oil Firing Scenario – 16 hrs/day, 225 hrs/yr						
NO_2	Annual	0.055	0.056	43.3	100	
	1 Hour[4]	42.14	42.84	407.9		470
CO	8 Hour	11.2	11.4	5,657	10,000	10,000
	1 Hour[3,4]	21.8	22.2	13,758	40,000	23,000

[1]Default ARM of 0.75 assumed to account for ozone-limited conversion of NO to NO_2.
[2]Maximum background concentration from 1997-1999 for the Otay Mesa monitoring station.
[3]Maximum background concentration from 1996-1998 for the Otay Mesa monitoring station.
[4]Based on the maximum one-hour emission rate; 69 lbs/hr for fuel oil firing for NOx, 27 lbs/hr for natural gas firing for CO.

As shown in the table, all impacts for NO_2 and CO are below the CAAQS and NAAQS. Therefore, the AQIA indicates that the project will comply with the requirements of Rule 20.2 for NO_2 and CO.

Because the background PM10 concentrations are already above the 24-hour CAAQS, further evaluation of PM10 impacts associated with the project will be conducted. The additional analysis is in progress and will be submitted upon completion to the District.

5.0 RULE 1200 EVALUATION

The initial health risk modeling results for one turbine operating at the Larkspur site indicated that the risks were below the Rule 1200 criteria for chronic noncancer risks and acute noncancer risks.

Table 8 presents the results of the Rule 1200 evaluation for two turbines operating at the Larkspur site based on the operational scenario described above (i.e., maximum operation on natural gas; 16 hrs/day, 225 hrs/year on fuel oil). The excess cancer risks based on the emission factors from AP-42 and the conservative assumptions inherent in the emission estimate for uncontrolled sources as well as the use of the multipathway factor for benzo(a)pyrene to represent the multipathway health effects of all PAHs leads to the conclusion that the excess cancer risks are likely overestimated. Furthermore, for the fuel oil scenario it was assumed that all chromium was hexavalent. These conservative assumptions lead to overestimation of the potential impacts from toxic air contaminant emissions.

Table 8
Results of Health Risk Calculations

	Risk Estimate	Rule 1200 Criterion	Above Criterion?
Natural Gas Firing			
Excess Cancer Risk	0.13 in 1 million	1 in 1 million	No
Chronic Noncancer HI	0.0025	1.0	No
Acute Noncancer HI	0.033	1.0	No
Fuel Oil Firing Scenario – 16 hrs/day, 225 hrs/yr per turbine			
Excess Cancer Risk	0.31 in 1 million	1 in 1 million	No
Chronic Noncancer HI	0.006	1.0	No
Acute Noncancer HI	0.043	1.0	No

As shown in Table 8, the excess cancer risks based on conservative assumptions are below the Rule 1200 threshold for uncontrolled sources to utilize TBACT. Therefore, no additional controls are required. The project will therefore be in compliance with Rule 1200.

Wildflower Energy Larkspur Facility

AQIA for CO Emissions - Uncontrolled Emissions

5-Mar-01

CO Emissions - Turbine 1

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
26.8	3.38

CO Emissions - Turbine 2

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
26.8	3.38

Maximum 1-hour CO Concentration

Turbine 1		Turbine 2							
Max. 1-hr X/Q [1]	Max. CO Impact	Max. 1-hr X/Q [1]	Max. CO Impact	CO 1-hour Concentration (ug/m^3)			CO 1-hour Standard (ug/m^3)		Exceed Standard?
				Total Modeled	Background [2]	Total	California	Federal	
6.46	21.829	6.57	22.191	44.021	13714.0	13,758.0	23000	40000	NO

Maximum 8-hour CO Concentration

Turbine 1		Turbine 2							
Max. 8-hr X/Q [1]	Max. CO Impact	Max. 8-hr X/Q [1]	Max. CO Impact	CO 8-hour Concentration (ug/m^3)			CO 8-hour Standard (ug/m^3)		Exceed Standard?
				Total Modeled	Background [3]	Total	California	Federal	
3.33	11.241	3.38	11.427	22.669	5634.0	5,656.7	10000	10000	NO

[1] Obtained from ISCST3 modeling

[2] Max. 1-hour value from Otay Mesa-Paseo International station 1996-1998 SDAPCD website data (12 ppm, or 13.7 mg/m^3 CO)

[3] Max. 8-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (4.93 ppm, or 5.63 mg/m^3 CO)

Wildflower Energy Larkspur Facility
AQIA for NOx Emissions - Unontrolled Emissions
5-Mar-01

NOx Emissions - Turbine 1

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
42.0	5.29	50.0	1.44

NOx Emissions - Turbine 2

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
42.0	5.29	50.0	1.44

Maximum 1-hour NO_2 Concentration

Turbine 1		Turbine 2							
Max. 1-hr X/Q [1]	Max. Modeled NOx 1-hr Conc. ($\mu g/m^3$)	Max. 1-hr X/Q [1]	Max. Modeled)x 1-hr Conc. (μg/	NO_2 1-hour Concentration ($\mu g/m^3$)			NO_2 1-Hour Standard ($\mu g/m^3$)		Exceed Standard?
				Max. Modeled [2]	Background [3]	Total	California	Federal	
6.46	25.65	6.57	26.07	51.72	322.9	374.6	470	None	NO

Annual Average NO_2 Concentration

Turbine 1		Turbine 2							
Ann. Avg. X/Q [1]	Max. Modeled NOx Ann. Conc. ($\mu g/m^3$)	Ann. Avg. X/Q [1]	Max. Modeled)x Ann. Conc. (μg/	NO_2 Annual Concentration ($\mu g/m^3$)			NO_2 Annual Standard ($\mu g/m^3$)		Exceed Standard?
				Max. Modeled [2]	Background [4]	Total	California	Federal	
0.05	0.055	0.05	0.056	0.11	43.2	43.3	None	100	NO

[1] Obtained from ISCST3 modeling

[2] Default ambient NO_2/NOx ratio of 0.75 used

[3] Max. 1-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.172 ppm, or 322.9 $\mu g/m^3$ NO_2)

[4] Max. annual value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.023 ppm, or 43.2 $\mu g/m^3$ NO_2)

Wildflower Energy Larkspur Facility

AQIA for NOx Emissions - Uncontrolled Emissions Only - Oil Firing 16 hrs/day

5-Mar-01

NOx Emissions - Turbine 1

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
69.0	8.69	50.0	1.44

NOx Emissions - Turbine 2

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
69.0	8.69	50.0	1.44

Maximum 1-hour NO_2 Concentration

Turbine 1		Turbine 2							
Max. 1-hr X/Q [1]	Max. Modeled NOx 1-hr Conc. ($\mu g/m^3$)	Max. 1-hr X/Q [1]	Max. Modeled NOx 1-hr Conc. ($\mu g/m^3$)	NO_2 1-hour Concentration ($\mu g/m^3$)			NO_2 1-Hour Standard ($\mu g/m^3$)		Exceed Standard?
				Max. Modeled [2]	Background [3]	Total	California	Federal	
6.46	42.14	6.57	42.84	84.97	322.9	407.9	470	None	NO

Annual Average NO_2 Concentration

Turbine 1		Turbine 2							
Ann. Avg. X/Q [1]	Max. Modeled NOx Ann. Conc. ($\mu g/m^3$)	Ann. Avg. X/Q [1]	Max. Modeled NOx Ann. Conc. ($\mu g/m^3$)	NO_2 Annual Concentration ($\mu g/m^3$)			NO_2 Annual Standard ($\mu g/m^3$)		Exceed Standard?
				Max. Modeled [2]	Background [4]	Total	California	Federal	
0.05	0.055	0.05	0.056	0.11	43.2	43.3	None	100	NO

[1] Obtained from ISCST3 modeling

[2] Default ambient NO_2/NOx ratio of 0.75 used

[3] Max. 1-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.172 ppm, or 322.9 $\mu g/m^3$ NO_2)

[4] Max. annual value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.023 ppm, or 43.2 $\mu g/m^3$ NO_2)

Wildflower Energy Larkspur Facility
AQIA for CO Emissions - Uncontrolled Emissions
5-Mar-01

CO Emissions - Turbine 1

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
15.0	1.89

CO Emissions - Turbine 2

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
15.0	1.89

Maximum 1-hour CO Concentration

Turbine 1		Turbine 2							
Max. 1-hr X/Q [1]	Max. CO Impact	Max. 1-hr X/Q [1]	Max. CO Impact	CO 1-hour Concentration (ug/m^3)			CO 1-hour Standard (ug/m^3)		Exceed Standard?
				Total Modeled	Background [2]	Total	California	Federal	
6.46	12.213	6.57	12.416	24.629	13714.0	13,738.6	23000	40000	NO

Maximum 8-hour CO Concentration

Turbine 1		Turbine 2							
Max. 8-hr X/Q [1]	Max. CO Impact	Max. 8-hr X/Q [1]	Max. CO Impact	CO 8-hour Concentration (ug/m^3)			CO 8-hour Standard (ug/m^3)		Exceed Standard?
				Total Modeled	Background [3]	Total	California	Federal	
3.33	6.290	3.38	6.393	12.683	5634.0	5,646.7	10000	10000	NO

[1] Obtained from ISCST3 modeling

[2] Max. 1-hour value from Otay Mesa-Paseo International station 1996-1998 SDAPCD website data (12 ppm, or 13.7 mg/m^3 CO)

[3] Max. 8-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (4.93 ppm, or 5.63 mg/m^3 CO)

Wildflower Energy Larkspur Facility

AQIA for PM10 Emissions - Uncontrolled Emissions

5-Mar-01

PM10 Emissions - Turbine 1

Max. 24-Hour PM10 Emissions		Annual Average PM10 Emissions	
(lb/day)	(g/sec)	(tons/yr)	(g/sec)
231.2	1.21	7.6	0.22

PM10 Emissions - Turbine 2

Max. 24-Hour PM10 Emissions		Annual Average PM10 Emissions	
(lb/day)	(g/sec)	(tons/yr)	(g/sec)
231.2	1.21	7.6	0.22

Maximum 24-hour PM10 Concentration

Turbine 1		Turbine 2							
Max. 24-hr		Max. 24-hr		PM10 24-hour Concentration (ug/m^3)			PM10 24-hour Standard (ug/m^3)		Exceed
X/Q [1]	Max. PM10 Impact	X/Q [1]	Max. PM10 Impact	Total Modeled	Background [2]	Total	California	Federal	Standard?
1.48	1.796	1.50	1.826	3.622	59.0	62.6	50	150	YES

Maximum Annual Average PM10 Concentration

Turbine 1		Turbine 2							
Max. Annual		Max. Annual		PM10 Annual Concentration (ug/m^3)			PM10 Annual Standard (ug/m^3)		Exceed
X/Q [1]	Max. PM10 Impact	X/Q [1]	Max. PM10 Impact	Total Modeled	Background [3]	Total	California	Federal	Standard?
0.05	0.011	0.05	0.011	0.023	28.3	28.3	30	50	NO

[1] Obtained from ISCST3 modeling

[2] Max. 24-hour value from Chula Vista station 1997-1999 CARB website data

[3] Max. annual value from Chula Vista station 1997-1999 CARB website data

Wildflower Energy Larkspur Facility
AQIA for CO Emissions - Dual Fuel Operational Scenario - 16 hrs/day
5-Mar-01

CO Emissions - Turbine 1

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
26.8	3.38

CO Emissions - Turbine 2

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
26.8	3.38

Maximum 1-hour CO Concentration

Turbine 1: Max. 1-hr X/Q [1]	Turbine 1: Max. CO Impact	Turbine 2: Max. 1-hr X/Q [1]	Turbine 2: Max. CO Impact	CO 1-hour Concentration (ug/m^3)			CO 1-hour Standard (u		Exceed
				Total Modeled	Background [2]	Total	California	Federal	Standard?
6.46	21.829	6.57	22.191	44.021	13714.0	13,758.0	23000	40000	NO

Maximum 8-hour CO Concentration

Turbine 1: Max. 8-hr X/Q [1]	Turbine 1: Max. CO Impact	Turbine 2: Max. 8-hr X/Q [1]	Turbine 2: Max. CO Impact	CO 8-hour Concentration (ug/m^3)			CO 8-hour Standard (u		Exceed
				Total Modeled	Background [3]	Total	California	Federal	Standard?
3.33	11.241	3.38	11.427	22.669	5634.0	5,656.7	10000	10000	NO

[1] Obtained from ISCST3 modeling

[2] Max. 1-hour value from Otay Mesa-Paseo International station 1996-1998 SDAPCD website data (12 ppm, or 13.7 mg/m^3 CO)

[3] Max. 8-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (4.93 ppm, or 5.63 mg/m^3 CO)

Wildflower Energy Larkspur Facility
AQIA for CO Emissions - Uncontrolled Emissions
5-Mar-01

CO Emissions - Turbine 1

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
26.8	3.38

CO Emissions - Turbine 2

Max. 1-Hour CO Emissions	
(lb/hr)	(g/sec)
26.8	3.38

Maximum 1-hour CO Concentration

Turbine 1		Turbine 2							
Max. 1-hr X/Q [1]		Max. 1-hr X/Q [1]		CO 1-hour Concentration (ug/m^3)			CO 1-hour Standard (ug/m^3)		Exceed
	Max. CO Impact		Max. CO Impact	Total Modeled	Background [2]	Total	California	Federal	Standard?
6.46	21.829	6.57	22.191	44.021	13714.0	13,758.0	23000	40000	NO

Maximum 8-hour CO Concentration

Turbine 1		Turbine 2							
Max. 8-hr X/Q [1]		Max. 8-hr X/Q [1]		CO 8-hour Concentration (ug/m^3)			CO 8-hour Standard (ug/m^3)		Exceed
	Max. CO Impact		Max. CO Impact	Total Modeled	Background [3]	Total	California	Federal	Standard?
3.33	11.241	3.38	11.427	22.669	5634.0	5,656.7	10000	10000	NO

[1] Obtained from ISCST3 modeling

[2] Max. 1-hour value from Otay Mesa-Paseo International station 1996-1998 SDAPCD website data (12 ppm, or 13.7 mg/m^3 CO)

[3] Max. 8-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (4.93 ppm, or 5.63 mg/m^3 CO)

Wildflower Energy Larkspur Facility

AQIA for NOx Emissions - Unontrolled Emissions

5-Mar-01

NOx Emissions - Turbine 1

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
42.0	5.29	50.0	1.44

NOx Emissions - Turbine 2

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
42.0	5.29	50.0	1.44

Maximum 1-hour NO_2 Concentration

Turbine 1		Turbine 2							
Max. 1-hr X/Q [1]	Max. Modeled NOx 1-hr Conc. ($\mu g/m^3$)	Max. 1-hr X/Q [1]	Max. Modeled)x 1-hr Conc. (μg/	NO_2 1-hour Concentration ($\mu g/m^3$)			NO_2 1-Hour Standard ($\mu g/m^3$)		Exceed
				Max. Modeled [2]	Background [3]	Total	California	Federal	Standard?
6.46	25.65	6.57	26.07	51.72	322.9	374.6	470	None	NO

Annual Average NO_2 Concentration

Turbine 1		Turbine 2							
Ann. Avg. X/Q [1]	Max. Modeled NOx Ann. Conc. ($\mu g/m^3$)	Ann. Avg. X/Q [1]	Max. Modeled)x Ann. Conc. (μg/	NO_2 Annual Concentration ($\mu g/m^3$)			NO_2 Annual Standard ($\mu g/m^3$)		Exceed
				Max. Modeled [2]	Background [4]	Total	California	Federal	Standard?
0.05	0.055	0.05	0.056	0.11	43.2	43.3	None	100	NO

[1] Obtained from ISCST3 modeling

[2] Default ambient NO_2/NOx ratio of 0.75 used

[3] Max. 1-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.172 ppm, or 322.9 $\mu g/m^3$ NO_2)

[4] Max. annual value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.023 ppm, or 43.2 $\mu g/m^3$ NO_2)

Wildflower Energy Larkspur Facility

AQIA for NOx Emissions - Uncontrolled Emissions Only - Oil Firing 16 hrs/day

5-Mar-01

NOx Emissions - Turbine 1

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
69.0	8.69	50.0	1.44

NOx Emissions - Turbine 2

Max. 1-Hour NOx Emissions		Annual Average NOx Emissions	
(lb/hr)	(g/sec)	(tons/yr)	(g/sec)
69.0	8.69	50.0	1.44

Maximum 1-hour NO_2 Concentration

Turbine 1		Turbine 2							
Max. 1-hr X/Q [1]	Max. Modeled NOx 1-hr Conc. ($\mu g/m^3$)	Max. 1-hr X/Q [1]	Max. Modeled NOx 1-hr Conc. ($\mu g/m^3$)	NO_2 1-hour Concentration ($\mu g/m^3$)			NO_2 1-Hour Standard ($\mu g/m^3$)		Exceed Standard?
				Max. Modeled [2]	Background [3]	Total	California	Federal	
6.46	42.14	6.57	42.84	84.97	322.9	407.9	470	None	NO

Annual Average NO_2 Concentration

Turbine 1		Turbine 2							
Ann. Avg. X/Q [1]	Max. Modeled NOx Ann. Conc. ($\mu g/m^3$)	Ann. Avg. X/Q [1]	Max. Modeled NOx Ann. Conc. ($\mu g/m^3$)	NO_2 Annual Concentration ($\mu g/m^3$)			NO_2 Annual Standard ($\mu g/m^3$)		Exceed Standard?
				Max. Modeled [2]	Background [4]	Total	California	Federal	
0.05	0.055	0.05	0.056	0.11	43.2	43.3	None	100	NO

[1] Obtained from ISCST3 modeling

[2] Default ambient NO_2/NOx ratio of 0.75 used

[3] Max. 1-hour value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.172 ppm, or 322.9 $\mu g/m^3$ NO_2)

[4] Max. annual value from Otay Mesa-Paseo International station 1997-1999 CARB website data (0.023 ppm, or 43.2 $\mu g/m^3$ NO_2)

AIR QUALITY IMPACT ANALYSIS

Criteria Pollutants
Health Risk Assessment

Wildflower Energy Larkspur Facility

Case: Turner SCR, 60 foot stack, Single turbine stack

	Turbine 1	Turbine 2
Turbine Output (MW):	49.9	49.9
MMBTU/hr	463.5	463.5
Btu/cf Conversion	1020	1020
Annual Operating Hours:	5950	5950
Max. 1-Hr. X/Q	6.46	6.57
Max. Annual Avg. X/Q	0.05106	0.05184

		Turbine 1				Turbine 2												Maximum		
		Emission Rates				Emission Rates				Max.	Max.	Cancer		Chronic		Acute	Acute			
	Emission Factor	Hourly		Annual		Hourly		Annual		1-Hour	Ann. Conc.	Inh URF	Cancer	Inh REL	Chronic	REL	REL Avg.	Cancer	Chronic	Acute
Substance	(lb/MMBTU)	(lb/hr)	(g/sec)	(lb/yr)	(g/sec)	(lb/hr)	(g/sec)	(lb/yr)	(g/sec)	(ug/m3)	(ug/m3)	(ug/m3)-1	MPF	(ug/m3)	MPF	(ug/m3)	Time (hrs)	Risk	HI	HI
Acetaldehyde	4.00E-05	1.85E-02	2.34E-03	1.10E+02	1.59E-03	1.85E-02	2.34E-03	1.10E+02	1.59E-03	3.04E-02	1.63E-04	2.70E-06	1	9.00E+00	1	n/a	n/a	4.41E-10	1.81E-05	N/A
Acrolein	6.40E-06	2.97E-03	3.74E-04	1.77E+01	2.54E-04	2.97E-03	3.74E-04	1.77E+01	2.54E-04	4.87E-03	2.61E-05	n/a	n/a	2.00E-02	1	1.90E-01	1	N/A	1.31E-03	2.56E-02
Ammonia		6.20E+00	7.81E-01	5.43E+04	7.81E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.05E+00	3.99E-02	n/a	n/a	2.00E+02	1	3.20E+03	1	N/A	1.99E-04	1.58E-03
Benzene	1.20E-05	5.56E-03	7.01E-04	3.31E+01	4.76E-04	5.56E-03	7.01E-04	3.31E+01	4.76E-04	9.13E-03	4.90E-05	2.90E-05	1	6.00E+01	1	1.30E+03	6	1.42E-09	8.16E-07	7.03E-06
1,3-Butadiene	4.30E-07	1.99E-04	2.51E-05	1.19E+00	1.71E-05	1.99E-04	2.51E-05	1.19E+00	1.71E-05	3.27E-04	1.76E-06	1.70E-04	1	n/a	n/a	n/a	n/a	2.98E-10	N/A	N/A
Ethylbenzene	3.20E-05	1.48E-02	1.87E-03	8.83E+01	1.27E-03	1.48E-02	1.87E-03	8.83E+01	1.27E-03	2.44E-02	1.31E-04	n/a	1	2.00E+03	1	n/a	n/a	N/A	6.53E-08	N/A
Formaldehyde	7.10E-04	3.29E-01	4.15E-02	1.96E+03	2.82E-02	3.29E-01	4.15E-02	1.96E+03	2.82E-02	5.40E-01	2.90E-03	6.00E-06	1	3.00E+00	1	9.40E+01	1	1.74E-08	9.66E-04	5.75E-03
Naphthalene	1.30E-06	6.03E-04	7.59E-05	3.59E+00	5.16E-05	6.03E-04	7.59E-05	3.59E+00	5.16E-05	9.89E-04	5.31E-06	n/a	n/a	9.00E+00	4.8	n/a	n/a	N/A	2.83E-06	N/A
PAHs	2.20E-06	1.02E-03	1.28E-04	6.07E+00	8.73E-05	1.02E-03	1.28E-04	6.07E+00	8.73E-05	1.67E-03	8.98E-06	1.70E-03	7.12	n/a	n/a	n/a	n/a	1.09E-07	N/A	N/A
Propylene Oxide	2.90E-05	1.34E-02	1.69E-03	8.00E+01	1.15E-03	1.34E-02	1.69E-03	8.00E+01	1.15E-03	2.21E-02	1.18E-04	3.70E-06	1	3.00E+01	1	3.10E+03	1	4.38E-10	3.95E-06	7.12E-06
Toluene	1.30E-04	6.03E-02	7.59E-03	3.59E+02	5.16E-03	6.03E-02	7.59E-03	3.59E+02	5.16E-03	9.89E-02	5.31E-04	n/a	n/a	3.00E+02	1	3.70E+04	1	N/A	1.77E-06	2.67E-06
Xylenes	6.40E-05	2.97E-02	3.74E-03	1.77E+02	2.54E-03	2.97E-02	3.74E-03	1.77E+02	2.54E-03	4.87E-02	2.61E-04	n/a	n/a	7.00E+02	1	2.20E+04	1	N/A	3.73E-07	2.21E-06
SUM																		***1.29E-07***	***2.500E-03***	***0.033***
Exceed Thresholds??																		NO	NO	NO
Max. hrs/yr increase:																		8760	8760	n/a

-- Emission factors from U.S. EPA AP-42, Section 3.1.

-- Cancer URFs are final values currently accepted by OEHHA and APCD; chronic and acute REL values are those adopted by OEHHA in May 2000

-- MPF factors are those provided by SDAPCD; MPF for PAHs is 7.12 for benzo(a)pyrene as recommended by Tom Weeks of the APCD.

-- Chronic and acute HI values summed across all target organs; results are conservative

-- Maximum one-hour and annual impacts anywhere were selected

Wildflower Energy Larkspur Facility

Case: Turner SCR, 60 foot stack, Single turbine stack

	Turbine 1	Turbine 2
Turbine Output (MW):	44.7	44.7
MMBTU/hr	421	421
Btu/cf Conversion	1020	1020
Annual Operating Hours:	225	225
Max. 1-Hr. X/Q	6.46	6.57
Max. Annual Avg. X/Q	0.05106	0.05184

		Turbine 1				Turbine 2														
		Emission Rates				Emission Rates				Max.	Max.	Cancer		Chronic		Acute	Acute	Maximum		
	Emission Factor	Hourly		Annual		Hourly		Annual		1-Hour	Ann. Conc.	Inh URF	Cancer	Inh REL	Chronic	REL	REL Avg.	Cancer	Chronic	Acute
Substance	(lb/MMBTU)	(lb/hr)	(g/sec)	(lb/yr)	(g/sec)	(lb/hr)	(g/sec)	(lb/yr)	(g/sec)	(ug/m3)	(ug/m3)	(ug/m3)-1	MPF	(ug/m3)	MPF	(ug/m3)	Time (hrs)	Risk	HI	HI
1,3-Butadiene	1.60E-05	6.74E-03	8.49E-04	1.52E+00	2.18E-05	6.74E-03	8.49E-04	1.52E+00	2.18E-05	1.11E-02	2.24E-06	1.70E-04	1	N/A	N/A	N/A	N/A	3.81E-10	N/A	N/A
Benzene	5.50E-05	2.32E-02	2.92E-03	5.21E+00	7.49E-05	2.32E-02	2.92E-03	5.21E+00	7.49E-05	3.80E-02	7.71E-06	2.90E-05	1	6.00E+01	1	1.30E+03	1	2.24E-10	1.29E-07	2.92E-05
Formaldehyde	2.80E-04	1.18E-01	1.49E-02	2.65E+01	3.81E-04	1.18E-01	1.49E-02	2.65E+01	3.81E-04	1.94E-01	3.93E-05	6.00E-06	1	3.00E+00	1	9.40E+01	1	2.36E-10	1.31E-05	2.06E-03
Naphthalene	3.50E-05	1.47E-02	1.86E-03	3.32E+00	4.77E-05	1.47E-02	1.86E-03	3.32E+00	4.77E-05	2.42E-02	4.91E-06	N/A	N/A	9.00E+00	1	N/A	N/A	N/A	5.45E-07	N/A
PAHs	4.00E-05	1.68E-02	2.12E-03	3.79E+00	5.45E-05	1.68E-02	2.12E-03	3.79E+00	5.45E-05	2.77E-02	5.61E-06	1.70E-03	7.12	N/A	N/A	N/A	N/A	6.79E-08	N/A	N/A
Arsenic	1.10E-05	4.63E-03	5.83E-04	1.04E+00	1.50E-05	4.63E-03	5.83E-04	1.04E+00	1.50E-05	7.60E-03	1.54E-06	3.30E-03	1	3.00E-04	1	1.90E-01	1	5.09E-09	5.14E-03	4.00E-02
Beryllium	3.10E-07	1.31E-04	1.64E-05	2.94E-02	4.22E-07	1.31E-04	1.64E-05	2.94E-02	4.22E-07	2.14E-04	4.35E-08	2.40E-03	1	4.80E-03	1	N/A	N/A	1.04E-10	9.05E-06	N/A
Cadmium	4.80E-06	2.02E-03	2.55E-04	4.55E-01	6.54E-06	2.02E-03	2.55E-04	4.55E-01	6.54E-06	3.32E-03	6.73E-07	4.20E-03	1	3.50E+00	1	N/A	N/A	2.83E-09	1.92E-07	N/A
Chromium	1.10E-05	4.63E-03	5.83E-04	1.04E+00	1.50E-05	4.63E-03	5.83E-04	1.04E+00	1.50E-05	7.60E-03	1.54E-06	1.50E-01	1	5.00E-03	1	N/A	N/A	2.31E-07	3.08E-04	N/A
Lead	1.40E-05	5.89E-03	7.43E-04	1.33E+00	1.91E-05	5.89E-03	7.43E-04	1.33E+00	1.91E-05	9.68E-03	1.96E-06	1.20E-05	1	N/A	N/A	N/A	N/A	2.36E-11	N/A	N/A
Manganese	7.90E-04	3.33E-01	4.19E-02	7.48E+01	1.08E-03	3.33E-01	4.19E-02	7.48E+01	1.08E-03	5.46E-01	1.11E-04	N/A	N/A	2.00E-01	1	N/A	N/A	N/A	5.54E-04	N/A
Mercury	1.20E-06	5.05E-04	6.37E-05	1.14E-01	1.63E-06	5.05E-04	6.37E-05	1.14E-01	1.63E-06	8.30E-04	1.68E-07	N/A	N/A	9.00E-02	1	1.80E+00	1	N/A	1.87E-06	4.61E-04
Nickel	4.60E-06	1.94E-03	2.44E-04	4.36E-01	6.27E-06	1.94E-03	2.44E-04	4.36E-01	6.27E-06	3.18E-03	6.45E-07	2.60E-04	1	5.00E-02	1	6.00E+00	1	1.68E-10	1.29E-05	5.30E-04
Selenium	2.50E-05	1.05E-02	1.33E-03	2.37E+00	3.41E-05	1.05E-02	1.33E-03	2.37E+00	3.41E-05	1.73E-02	3.50E-06	N/A	N/A	5.00E-01	1	N/A	N/A	N/A	7.01E-06	N/A
SUM																		***3.08E-07***	***6.048E-03***	***0.043***
Exceed Thresholds??																		NO	NO	NO
Max. hrs/yr increase:																		730	8760	n/a

-- Emission factors from U.S. EPA AP-42, Section 3.1.

-- Cancer URFs are final values currently accepted by OEHHA and APCD; chronic and acute REL values are those adopted by OEHHA in May 2000

-- MPF factors are those provided by SDAPCD; MPF for PAHs is 7.12 for benzo(a)pyrene as recommended by Tom Weeks of the APCD.

-- Chronic and acute HI values summed across all target organs; results are conservative

-- Maximum one-hour and annual impacts anywhere were selected

WILDFLOWER ENERGY LP
OTAY MESA BORDER
Larkspur PROJECT

Simple Cycle LM-6000 Sprint Peaking Plant

Originally Prepared for Wildflower Energy LP
February, 2001
(March, 2001 Submittal for Second Turbine)

Sterling Energy Operations
26893 Calle Hermosa
Capistrano Beach, Ca 92624
949 940 9160

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1) Project Overview

A) Project Description

Wildflower Energy LP proposes to install a General Electric (GE) LM –6000 Gas Turbine. The system will be operated as a simple cycle power plant, fired primarily on natural gas, with a total site output not to exceed 49.9 MW. The plant will provide transmission and distribution (T&D) support flexibility and power to the grid during periods of high electricity demand. One simple cycle gas turbine with an individual stack, will be installed along Harvest Road (*reference application and site map*), in the Otay Mesa Development area. The proposed installation will use a GE turbine equipped with a conventional GE combustor and water injection, to reduce the NOx to approximately 25 ppm. The Turbine exhaust will then be controlled with a dedicated Selective Catalytic Reduction (SCR) system, using Aqueous ammonia, to reduce the NOx emission to below 5 ppm corrected to 15%. Annual NOx emissions from the site will be below major stationary source. Air Quality Impacts Analysis (AQIA) thresholds that were triggered are presented in the modeling section of this permit application.

B) Best Available Control Technology (BACT)

This Best Available Control Technology (BACT) evaluation has been prepared in accordance with the current San Diego Air Pollution Control District (District) Regulation II, Rules 20.1 through 20.9, New Source Review (NSR). This BACT evaluation addresses control of NOx, VOC, PM10, SO2. and NH3 emissions from a proposed limited use simple cycle gas turbine installation with a net site electrical output of not greater than 49.9 MW.

A "*Top Down*" approach is used in this BACT analysis, following the guideline provided to all U.S. EPA regional administrators in December 1987:

"The first step in this approach is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. "

The factored cost estimation procedure developed by the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) and presented in the EPA's <u>Control Cost Manual, 5th Edition</u> (1996) was considered for this evaluation. However, because the top control technology has been selected, a cost-effectiveness analysis is not necessary.

The subsequent sections of this report will serve to establish the current regulatory BACT requirements for a simple cycle gas turbine at the stated output levels, review technically feasible control technologies, and provide supportive back-up documentation as referenced and required.

2) Regulatory Analysis BACT

A) Federal PSD permit criteria trigger levels

The criteria pollutant emission levels that triggers a Federal *new major stationary source* PSD permit application requirement is either;

- *100 tons / year for any of the 28 source categories specified in 40 CFR 52.21*
- *or 250 TPY for all other source types*

Major modifications to a major source stationary source trigger PSD requirements if the proposed project net emissions are as follows:

- *15 tons/year for PM10*
- *40 tons/year for VOC*
- *40 tons/year for NOx*
- *40 tons/year for SO2*
- *100 tons/yr for CO*

A BACT analysis is required for a pollutant that triggers the PSD permit application requirement. The emissions levels from this proposed gas turbine installation will not trigger Federal PSD review requirements for any pollutant.

B) San Diego APCD New Source Review (NSR)

The intent of the San Diego Air Pollution Control (SDAPCD) New Source Review (NSR) rule is to establish pre-construction review requirements for new and modified stationary sources of air pollution, per the following

- Determine the applicability of BACT
- Determine the need to analyze air quality impacts
- Ensure that the operation of such sources, do not interfere with the attainment or maintenance of ambient air quality standards.

The NSR rule also states that emissions of non-attainment pollutants from major modifications to major stationary sources must be offset. San Diego County is a *Federal* non-attainment area for ozone. San Diego County is a California non-attainment area for ozone, PM10, VOC, and NOX; ozone precursors are VOC and NOX.

The District requires that BACT be applied to any new emission sources that results in a potential to emit greater than or equal to 10 lbs/day for NOx, VOC, PM10, and SO2. As a result, the emissions associated with the proposed gas turbine power plant trigger San Diego County

NSR review for NOx, VOC, PM10, and SO2. Additionally, ammonia slip will be minimized to ensure minimal adverse impact.

	Federal	**California**	**San Diego County**
Non-attainment	Ozone	Ozone, PM10, NOx, VOC	
NSR (New Source Review)			NOx, VOC, PM10, SO2

The District defines BACT as the most effective emission control device, emission limit, or technique which has been required or used for the type of equipment comprising such emission unit, unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer (APCO) that such limitations are not achievable. BACT is also defined as any other emission control device or technique, alternative basic equipment, different fuel or process, determined to be technologically feasible and cost effective by the APCO. It is understood that a NOx control cost effectiveness of $12,900 per ton of pollutant removed, in 1999 dollars, is currently used by the District as the cost effectiveness ceiling for requiring BACT for NOx. The VOC control cost-effectiveness of $7,500 per ton of pollutant removed, in 1999 dollars, is currently used by the District as the cost effectiveness ceiling for requiring BACT for VOC.

i) Baseline Emission Rate

The baseline emission rate represents a "*realistic scenario of upper bound controlled emissions for the source.*" Typically the baseline emission rate is based on uncontrolled emissions, using a realistic upper boundary operating assumption. Use of an uncontrolled emission rate is appropriate for the gas turbines covered by this BACT evaluation, which include the use of a GE LM 6000 Sprint machine. The exhaust of the proposed Gas Turbine will be equipped with an SCR designed to reduce the **emissions to below 5 ppm NOx corrected to 15% O2**.

ii) Top-Down BACT Determination

If a cost effectiveness calculation was required, then consideration would be given to the EPA's OAQPS Control Cost Manual which provides general guidance regarding what cost elements should be included in the cost analysis. However, because the top control technology has been selected, which in this case the application of a high temperature aqueous SCR system, *a cost-effectiveness analysis is not required.* For VOC, the cost-effectiveness for add-on control of an oxidation catalyst is further discussed in this evaluation.

3) Proposed BACT and Technically Feasible Control Technologies

The following table summarizes some recent proposed BACT for applicable pollutants emitted from similar Gas Turbines to be used for T&D support and power to the grid during periods of high electricity demand. Additionally, this Gas Turbines *primary* fuel will be fired on Natural Gas.

Turbine	Output MW	Location	NOx inlet	NOx outlet	NH3 slip	Exhaust Temp (F)	Issue Date of Permit	Type of plant
Frame 5	16.1	Escondido	150	5	10	890	2000	Peaker
Frame 5	16.1	Escondido	150	5	10	890	2000	Peaker
LM 6000	42	Carson Cogen Sacramento	80	5	20	900	1993	N/a
Frame 5	24	Redding, Ca	42	9	10	990	1995	Peaker

NOx Emissions – Use of the TOP control technology is proposed. SCR applied to an uncontrolled Gas Turbine to achieve a NOx limit of less than 5 ppm corrected to 15% O2, and ammonia slip limited to less than 10 ppm, is proposed as BACT. The *above* table presents of list of the most recent installations achieving the BACT / BARCT Emission level for a simple cycle *Peaker* gas turbine firing on Natural Gas.

VOC Emissions - Natural gas firing is proposed as VOC BACT. Two of the most recent San Diego APCD gas turbine BACT decisions, Ice Flow LP (Escondido) and Bay Side (National City), have identified natural gas combustion as BACT for VOC stack emissions. Reference Appendix B for economic evaluation and the following section for supportive discussion.

PM10 Emissions - Natural gas firing is proposed as PM10 BACT. Two of the most recent San Diego APCD gas turbine BACT decisions, Ice Flow LP (Escondido) and Bay Side (National City), have identified natural gas combustion as BACT for PM10 stack emissions.

SO2 Emissions - Natural gas firing is proposed as SO2 BACT. Two of the most recent San Diego APCD gas turbine BACT decisions, Ice Flow LP (Escondido) and Bay Side (National City), have identified natural gas combustion as BACT for SO2.

B) Technically Feasible Control Technologies

Oxides of Nitrogen (NOx)

The "top" NOx control option of SCR is proposed in this BACT evaluation. SCR applied to an uncontrolled turbine, with NOx controlled to a concentration limit of 5 ppm, has been identified as BACT for this unit. The target NOx level for this proposed turbine is less than 5 ppm corrected to 15% O2. This NOx level is based on the California Air Resources Board (CARB) guidance document for projects undergoing the California Energy Commission's (CEC's) power plant siting process. The CARB recommended NOx BACT level for simple-cycle plant configuration is 5 ppm. Although the proposed simple-cycle turbines are not subject to the CEC process, Wildflower Energy LP proposes to meet this limit. In order to achieve this level, SCR will be applied to the turbine, with NOx controlled to 5 ppm corrected to 15% O2, and ammonia slip to less than 10 ppm, which has been identified as BACT for this unit.

Turbine operations at the facility will be permitted for the maximum hours per year for maximum flexibility to stay below the major source thresholds for the facility. (*Refer to permit application section on emission estimates for turbine specifications, facility emission estimates and annual hours of operation.*) The facility will be a non-major stationary source; NOx, CO and PM10 trigger AQIA requirements. (*Refer to air quality impact analysis section for permit application.*)

Volatile Organic Compounds (VOC)

Reference cost-effectiveness tables for an economic cost effectiveness evaluation of applying a control device to reduce the VOC emissions form this Turbine. While 8,760 hours per year was used for the purposes of calculation, and worst case scenario, it is unlikely this plant will ever operate at that number of hours. It did seem wise though, in these times of power uncertainty, to provide for the most operating flexibility. Additionally, an estimate of 11.68 lb/hr of VOC was used in the calculation of emission estimates. This is a conservative estimate based on the total hydrocarbon estimate (THC) provided by the turbine vendor emission guidelines. This is a reasonably high estimate which does not discount for the VOC percentage (25%) in the THC, resulting in a very conservative emission level. By accounting for the VOC portion, an estimated 2.92 lbs/hr of VOC uncontrolled results. Additionally, even at this high number of operating hours, the emission level is below the 50 ton per year thresh hold. Finally, in review of the final cost determination using EPA's cost-estimation assumptions, the $8,581 dollars per ton of THC effectiveness, with a comparable VOC cost-effectiveness of $34,325 (*See supporting cost-effetiveness tables.*) – are both higher than the guideline level of $7,500 per ton.

Additionally, an actual cost estimate was obtained from a vendor, ARB, Inc., Lake Forest, California. The cost estimate is provided, along with the cost effectiveness evaluation with this actual estimate. The cost basis is for the VOC catalyst and specific cost relating to just the VOC catalyst installation and appurtenances. The specific cost for startup of the catalyst were obtained from the catalyst vendor, Peerless Mfg. Co., Dallas, Texas. The results of this estimate yielded a $9,046 dollars per ton of THC removed, with a comparable $36,185 for VOC removed. Both are higher than the guideline level of $7,500 per ton. Following the precedence of the most recent San Diego APCD gas turbine, Peaker type installations, the SDAPCD have identified natural gas combustion as BACT for VOC.

It should be noted that in estimating the VOC component of the THC, and applying this as the uncontrolled emission rate, no correction was made for the comparable VOC ppm value, and thus the estimates for total VOC removed is also more than expected, e.g., not as much as 80% to reduce emissions to 2 ppm VOC.

Particulate Matter (PM10)

The two most recent San Diego APCD gas turbine BACT decisions have identified natural gas combustion as BACT for PM10. The cost effectiveness of any high efficiency PM10 control device, such as a baghouse or electrostatic precipitator, would be prohibitive in this application. There are no gas turbine installations in the United States that use natural gas as fuel, and also employ end-of-pipe PM10 controls.

Oxides of Sulfur (S02)

The two most recent San Diego APCD gas turbine BACT decisions have identified natural gas combustion as BACT for SO2. The cost effectiveness of any high efficiency SO2 control device, such as a wet scrubber, would be prohibitive in this application. There are no gas turbine installations in the United States that use natural gas as fuel, and also employ end-of-pipe SO2 controls.

REFERENCES SOURCES

1. U. S. EPA. Office of Air Quality Planning and Standards, OAQPS Cost Control Manual - 5th Edition, EPA 450/3-90-006, January 1996.

2. U. S. EPA, New Source Review Workshop Manual Prevention of Significant Deterioration and Non-Attainment Area Permitting (draft), Chapter 8 - Best Available Control Technology, October 1990.

3. California Air Resources-Board, Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines, Criteria Pollutants Branch, Stationary Source Division, May 1992.

4. U. S. EPA, Office of Air Quality Planning and Standards, Alternative Control Techniques (BACT Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993.

5. U. S. EPA, Office of Air Quality Planning and Standards, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources Table 3.1 -3, January 1995.

6. California Air Resources Board, Identification of Volatile Organic Compound Species Profiles, ARB Specification Manual Second Edition, Volume I of 2, Profile 719, August 1991.

7. Powers Engineering, Submittal Package for PG&E Peaking Unit Application, September, 2000.

8. Lefebvre, A. H., The Role of Fuel Preparation in Low-Emission Combustion, Journal of Engineering for Gas Turbines and Power, American Society of Mechanical Engineers, Volume 117, pp. 617-654, October 1995.

9. BAAQMD, SCAQMD, SDAPCD, and CARB Website reference material.

Alternative Control Technologies

Oxides of Nitrogen (NOx)

A description of turbine combustor modifications and back-end controls that are available to reduce NOx emissions are presented in the following text;

Combustor Modifications: Water Injection, DLN, Catalytic Combustor

Water Injection. Water injection has been used for that past 25 years to control NOX emissions from gas turbines. Manufacturers typically guarantee water injected combustors to 42 ppm when firing natural gas. The maximum allowable water injection rate is determined by;

1) the CO and VOC limits on the unit, as water injection has a quenching effect that increases emissions of "*products of incomplete combustion*," and,

2) the rapid wear caused by direct water impingement on the combustor liner. As an example, water impingement on the combustor liner becomes a problem at "*water-to-fuel ratio*" (WFR) above 1.0 for some turbine designs, resulting in rapid liner wear.

Dry Low NOx (DLN) Combustors. Conventional combustors are diffusion controlled. The fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot spots that produce high levels of NOx. In contrast, DLN combustors generally operate in a premixed mode, where air and fuel are mixed before entering the combustor. In premixed flames, the underlying principle is to supply the combustion zone with a completely homogenous, lean mixture of fuel and air. This homogenous mixing, generally results in a much lower production NOx compounds during combustion. Additionally, a useful byproduct of DLN combustion is that it is essentially free of carbon formation, especially when gaseous fuels are used. The absence of carbon not only eliminates soot emissions but also greatly reduces the amount of heat transferred to the combustor liner walls by radiation, thereby reducing the amount of air needed for liner wall cooling. This is an important factor as it means that more air is available for lowering the temperature of the combustion zone and improving the combustor pattern factor.

Another important advantage of the DLN combustor is that the amount of NOx formed does not increase with an increase in residence time. This means that DLN systems can be designed with long residence times to achieve low CO and VOC emissions, while maintaining low NOX levels. For a given turbine, the DLN combustor volume is typically twice that of a conventional combustor.

Catalytic Combustors. The strong dependence of NOx formation on flame temperature means that NOx emissions are lowest when the combustor is operating close to the lean flameout limit. One method of extending the lean flameout limit down to lower air-fuel ratios is by incorporating a combustion-enhancing catalyst within the combustor. Catalytic combustion is a flameless process, allowing fuel oxidation to take place at temperatures well below the normal lean flammability limits of the air-fuel mixture. For this reason, the use of catalysts in gas turbine combustion to replace part of the thermal reaction zone allows stable combustion to occur at peak temperatures that are as much as 1,800 °F lower than those of conventional combustors. One problem with catalytic combustors is a tendency toward auto-ignition of the fuel upstream of the catalyst. Although the air-fuel ratios are well below the lean flammability limit and in theory, should not be susceptible to auto-ignition, locally richer mixtures can exist near the fuel injector before complete mixing has taken place. Thus, it is essential that mixing be achieved in less than the auto-ignition delay time. Optimum catalyst performance also requires the inlet air-fuel mixture to be completely uniform in regard to temperature, composition, and velocity profile, since this assures effective use of the entire catalyst area and prevents damage to the substrate due to local high gas temperatures.

In addition to DLN, other NOx reduction technologies, including catalytic combustion, are included within the scope of the R&D projects covered by the U.S. Department of Energy s Advanced Turbine System program. Catalytica, Inc. (Mountain View, CA) is one of the leading developers of combustor catalysts for gas turbines. Catalytica has developed an all-metal catalyst substrate that eliminates the potential problems associated with the limitations of high temperature ceramic substrates in this application. The maximum temperature reached in the catalyst is approximately 1,700 °F. Any additional temperature rise above 1,700 °F would potentially damage the metal substrate.

All fuel and air is added upstream of the catalyst. By system design, only approximately 50 percent of the fuel is oxidized in the catalyst, resulting in a temperature rise to approximately 1,700 °F. The peak temperature of 1,700 °F reached across the catalyst is sufficiently high to completely oxidize the remaining 50 percent of the fuel downstream of the catalyst.

Catalytic combustors have been tested by various organizations. Catalytica has performed a 1,000 hour test of the catalytic combustor in a 1.5 MW Kawasaki gas turbine. This test ended in, mid-November 1997. This combustor is to be placed in a 1.5 MW Kawasaki turbine located at a cogeneration plant in London, Ontario, Canada. Two 1.5 MW Kawasaki turbines located at a cogeneration plant in Maryland were retrofitted with catalytic combustors in 1998. Catalytic combustors have been tested in large GE turbines at the GE test facility in Schenectady, New York. NOx averaged less than 3 ppm and CO less than 5 ppm corrected to 15 percent O2 during a test on a Frame 9E turbine. At one time, GE had announced a Memorandum of Understanding with Catalytica to develop catalytic combustors for all GE turbine models through Frame 7E..

One of the major advantages of the catalytic combustor, in addition to inherently low emissions, is low vibration and acoustic noise. DLN combustors tend to create harmonics in the combustor that result in significant vibration and acoustic noise. Limited test data indicate that the vibration and acoustic noise levels generated in combustors equipped with catalytic combustors are one tenth to one-hundredth the levels measured in the same turbine equipped with DLN combustors.

NOx Control: SCR, SCONOx™, and SNCR

Selective Catalytic Reduction (SCR). The SCR process consists of injecting ammonia upstream of a catalyst bed. It is critical to the design of the SCR to produce efficient and complete mixing prior to the ammonia making contact with the catalyst surface. NOx combines with the ammonia embedded on the catalyst surface, and is reduced to molecular nitrogen through the activation energy of the catalyst. SCR is capable of over 95 percent NOx *reduction (reference Peerless Mfg. Co. Dallas, Tx.)* Titanium Oxide in a homogenous extruded substrate is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used, depending on the type of fuel and operating temperature of the exhaust gas. The ideal operating temperature for a conventional SCR catalyst is 450 to 750 °F.

Typically, the catalyst reactor is mounted on a spool piece, located within the HRSG or in the discharge duct before the stack section, at a location where the gas temperature of a combined cylce plant is typically in the ideal range of 450 to 750 "F. High temperature zeolite SCR catalysts for Simple Cycle applications have been developed that permit continuous SCR operation at temperatures as high as 1050 F. High temperature SCR catalysts must be used with simple cycle gas turbine installations such as the proposed T&D support turbine installation, as simple cycle gas turbine exhaust temperature ranges from 850 to 1000 F range.

A certain amount of ammonia slip occurs when using SCR. Ammonia slip is usually limited by permit conditions to 10 or 20 ppm, corrected to 15 percent 02. Ammonia is classified as an air toxic compound in California. Ammonia passing through the SCR and emitted to atmosphere can combine with nitrate (NOx) or sulfate (S04) in the ambient air to form a secondary particulate, either ammonium nitrate or ammonium sulfate. Based on 1995 District data, ambient NOx and S04 concentrations are greater than ambient ammonia concentrations. The secondary particulate formation mechanism is "ammonia-limited" in the San Diego area, indicating that ammonia released to the atmosphere would tend to form secondary particulate.

SCONOX ™Catalytic Absorption System The EPA recently certified an innovative catalytic NOX reduction technology, SCONOx™, as a "*demonstrated in practice*" LAER-level technology for gas turbine NOx reduction. SCONOx™ employs a precious metal catalyst and a NOx absorption/regeneration process step to convert CO and NOx to CO2, H20 and N2. The principal difference of the SCONOx™ technology over Selective Catalytic Reduction (SCR) is the elimination of ammonia emissions and the simultaneous reduction of CO, VOCs and NOX. The elimination of ammonia emissions also eliminates the possibility of secondary PM10 ammonium nitrate or ammonium sulfate formation. However, the regeneration gas is discharged into the stack raising the questions of H2S or other related formations. A SCOSOx™ catalytic coating can also be added to the oxidation catalyst to effectively remove SO2 from the exhaust gas.

NOx binds to the potassium carbonate absorbent coating the surface of the oxidation catalyst in the SCONOx™ reactor. Each module within the reactor becomes saturated with NOX over time and must be desorbed. Regeneration is accomplished by isolating the module via stainless steel louvers and injecting hydrogen diluted with steam. Hydrogen is generated onsite using a small reformer that uses natural gas and steam as input streams. The hydrogen concentration of the regeneration gas is typically 5 percent. The hydrogen reacts with the absorbed NOx to form N2 and H2O, leaving the potassium carbonate ready for another absorption cycle. If an SO2 absorbent is added, the module is desorbed in the same manner, resulting in the formation of H2S. Regeneration gases can be passed through an H2S scrubber to remove the captured sulfur.

SCONOX technology is not considered technically feasible in this application due to the 700 °F maximum temperature limitation. The exhaust gas temperature of a simple cycle gas turbine is 850 to 1,000 °F. SCONOX technology is also designed to operate downstream of a combustor enhanced NOX control system, such as water injection or dry low NOX (DLN). SCONOx™ NOX absorption beds are designed to absorb for several minutes prior to regeneration, assuming an inlet NOX concentration at a maximum of 25 to 30 ppm. At an inlet NOX concentration of 120 to 150 ppm, the absorption bed would become saturated so quickly that the regeneration step could not be completed prior to the next absorption bed in line becoming saturated and requiring regeneration. The only options available to address this problem are: 1) increase the size of the SCONOx™ unit by a factor of 3 to 4, making it prohibitively expensive. or 2) add either water injection or DLN to the turbine combustor to drop the NOx concentration at the SCONOX inlet.

Selective non-Catalytic Reduction (SNCR) In the SNCR process, a reducing agent such as urea or ammonia is *Free-injected* into a high temperature zone of the exhaust ductwork to reduce NOx to molecular nitrogen. No catalyst bed is used, and a reaction temperature greater than 1,400 "F is generally required. This technology has been used almost exclusively with Utility type boilers and achieves a NOx control efficiency of 50 to 80 percent in the boiler application. SNCR has not been installed on a gas turbine as there is insufficient gas residence time at the required temperature to effectively control NOx.

Volatile Organic Compounds (VOC) The total hydrocarbon (THC) emission guarantee provided by the primary vendor of the turbine for this project, General Electric, is 11.68 lb/hr (as methane) at 15 percent O2. Gas turbine THC speciation data available from the EPA (AP-42) indicates that less than 25 percent of the THC measured in gas turbine exhaust gas is non-methane hydrocarbons. THC speciation data available from the California Air Resources Board indicates that approximately 10 percent of the THC measured in gas turbine exhaust gas is non-methane, non-ethane hydrocarbons. Assuming that 25 percent of the THC guarantee level is non-methane, non-ethane hydrocarbons, also known as Volatile Organic Compounds (VOC), the VOC emission rate would be less than 13 tpy. The control cost effectiveness of a VOC oxidation catalyst in this application would be prohibitive given the low VOC emission rate.

The two most recent San Diego APCD gas turbine BACT decisions, Ice Flow LP (Escondido) and Bay Side (National City), have identified natural gas combustion as BACT for VOC's.

Particulate Matter (PM10)
The two most recent San Diego APCD gas turbine BACT decisions have identified natural gas combustion as BACT for PM10.

Oxides of Sulfur (SO2)
The two most recent San Diego APCD gas turbine BACT decisions have identified natural gas combustion as BACT for SO2.

Ammonia Slip (NH3) In connection with BACT determinations for NOx, permitting agencies have generally sought permit limits for NH3 slip of 10 ppm corrected to 15 percent 02, for gas turbines using SCR for NOX control. The two most recent San Diego APCD gas turbine BACT decisions have limited NH3 slip to 10 ppm. Two recent San Joaquin Valley Unified APCD gas turbine BACT determinations require NOx limits of 3.8 ppm and 3.0 ppm. In both of these cases, NH3 slip limits were relaxed to 20 ppm and 25 ppm, respectively. To achieve a 1 to 2 ppm incremental reduction in NOx from a 5 ppm NOx BACT level, the San Joaquin Valley Unified APCD is willing to accept a potential **NH3 emissions increase of 10-15 ppm.**

GAS TURBINE PROCESS DESCRIPTION, OPERATIONS AND NOx EMISSIONS

Gas Turbine Process Description

The turbine consists of a compressor, combustor, and a power turbine. The compressor provides pressurized air to the combustor where fuel is burned. Hot combustion gases leave the combustor and enter the turbine section. In the turbine section, the gases are expanded across the power turbine blades to rotate one or more shafts. These drive shafts power the compressor and the electric generator. The thermal efficiency of a simple cycle turbine ranges from 24 to 30 percent, and depends principally on compression ratio and firing temperature. The simple cycle turbine exhaust gas temperature ranges from 850 to 1,000 °F for the turbine models that will be used in the proposed project.

In the proposed project, a simple cycle gas turbines will be used to achieve a site rating of not greater than 49.5 MW. Each turbine will be equipped with a separate NOx control system and exhaust stack.

<u>Turbine Process or Equipment Operations that Affect NOx Emissions</u> Virtually all gas turbine NOx emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO2 molecule. There are three mechanisms by which NOx is formed in turbine combustors, namely Thermal NOx, NOx which is formed at high temperatures inside the combustor, prompt NOx, which is quickly formed upon combustion of a fuel, and Fuel NOx, which is formed ffrom the bound up Nitrogen in the fuel. These mechanisms are discussed in greater detail in the following paragraphs.

Thermal NOx is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. The major contributing chemical reactions are known as the Zeldovich mechanism and take place in the high temperature area of the gas turbine combustor. Simply stated, the Zeldovich mechanism postulates that thermal NOx formation increases exponentially with increases in temperature and linearly with increases in residence time. Flame temperature is dependent on the air/fuel ratio. The Fuel/Air stoichiometric ratio is the point at which a flame burns at its highest theoretical temperature.

Prompt NOx, a form of thermal NOx, is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NO are oxidized to form NOx. Prompt NOx is formed in both fuel-rich flame zones and dry low NOx (DLN) combustion zones. The contribution of prompt NOx to overall NOx emissions is relatively small in conventional near-stoichiometric combustors, however, this contribution is an increasingly significant percentage of overall thermal NOx emissions in DLN combustors. For this reason, prompt NOx becomes an important consideration for DLN combustor designs, and establishes a minimum NOx level attainable in lean mixtures.

Fuel NOx is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as fuel bound nitrogen, N2, in some natural gas, does not contribute significantly to fuel NOx formation. Some low-Btu synthetic fuels contain nitrogen in the form of ammonia (NH.), and other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NOx. With excess air, the degree of fuel NOx formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NOx decreases with increasing nitrogen content, although the absolute magnitude of fuel NOx increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NOx, whereas a fuel with a 1.0 percent FBN may have only a 40 percent conversion rate. Natural gas typically contains little or no FBN. As a result, when compared to thermal NOx, fuel NOx is not currently a major contributor to overall NOx emissions from stationary gas turbines firing natural gas.

The level of NOx formation in a gas turbine, and hence the NOx emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NOx generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine. These factors are discussed below.

Combustor Design The design of the combustor is the most important factor influencing the formation of NOx. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NOx formation. Thermal NOx formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NOx formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NOx production takes place.

Injecting water or steam into a conventional combustor provides a heat sink, adds mass that effectively reduces peak flame temperature, thereby reducing thermal NOx formation. Premixing air and fuel at a fuel lean ratio approaching the lean flammability limit (approximately 50 percent excess air) significantly reduces peak flame temperature, resulting in minimum NOx formation during combustion. This is known as dry low NOx (DLN) combustion.

Type of Fuel The level of NOx emissions varies for different fuels. In the case of thermal NOx, this level increases with flame temperature. For gaseous fuels, the constituents in the gas can significantly affect NOx emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (such as ethane, propane and butane) burn at higher flame temperatures, and as a result can increase NOx emissions greater than 50 percent over NOx levels for methane gas fuel. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons. Conversely, gas fuels that contain significant inert gases, such CO2, generally produce lower NOx emissions. These inert gases serve to absorb heat during combustion, thereby lowering flame temperatures and reducing NOx emissions. Examples of this type of gas fuel are air-blown gasifier fuels and some field gases. Combustion of hydrogen also results in high flame temperatures, and gases with significant hydrogen content produce relatively high NOx emissions.

Distillate oil burns at a flame temperature that is approximately 150 °F higher than that of natural gas. As a result, NOx emissions are higher when distillate oil is burned instead of natural gas. Low-Btu fuels such as coal gas burn with lower flame temperatures, which result in substantially lower thermal NOx emissions than those produced by natural gas or distillate oil.

Ambient Conditions Ambient conditions that affect NOx formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NOx formation. The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures that reduces thermal NOx formation. At low humidity levels, NOx emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NOx formation varies. At high humidity levels and low ambient temperatures, NOx emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 50 °F, NOx emissions decrease with increasing temperature. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor, and therefore NOx production levels increase with increases in ambient temperature.

Operating Cycles

NOx emissions from identical turbines used in simple cycle and cogeneration cycles have similar emissions, provided no duct burner is used in heat recovery applications. Emissions are similar because NOx is formed only in the turbine combustor, and remains at the combustor outlet NOx level regardless of downstream exhaust gas temperature reductions.

Power Output Level

The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature. Each turbine has a base-rated power level and corresponding NOx level. At power outputs below the base-rated level, the flame temperature is lower, so NOx emissions are lower. Conversely. at peat power outputs above the base rating, NOx emissions are higher due to higher flame temperature.

Operating Procedures Affecting NOx Emissions The two operating procedures affecting emissions are fuel type and load. Distillate oil has both a higher flame temperature than natural gas and a higher concentration of fuel-bound nitrogen. As a result, the uncontrolled baseline NOX emission rate is higher with distillate oil than with natural gas.

DLN combustor technology uses the concept of hybrid combustion, combining diffusion flame plus DLN flame combustor technology. Due to the flame instability limitations of the DLN combustor below approximately 50 percent of rated load, the turbine is operated in a conventional diffusion flame mode until the load reaches approximately 50 percent.

Load plays an important role in the NOx emission rate. In conventional combustors, which include DLN combustors operating at less than 50 percent load, fuel is injected into the base of the combustor. Air is injected along the length of the combustor, to provide both combustion air and "quenching air" to cool the combustor exhaust gas before it reaches the turbine blades. As a result of the combustor design, a fuel rich environment is maintained in the immediate vicinity of the fuel injector. As the fuel diffuses into the combustion/cooling air supply, combustion takes place. At low loads, the reaction kinetics are such that combustion proceeds at a relatively **fuel** rich ratio and combustion products are quenched rapidly. At high load, the flame front reaches its maximum size and length. There is also greater turbulence in the combustor, resulting in a greater percentage of the fuel being combusted in "hot spots" at or near stoichiometric conditions, and less air is available to quench the products of combustion. As a result, NOx emissions are greatest at high load conditions.

In addition to fuel type and load, the "water-to-fuel ratio" (WFR) has a direct impact on the controlled NOx emission rate. The water injection flowrate is controlled by the turbine inlet temperature and by ambient temperature. WFR's up to 0.6 - 0.8 generally result in little or no contributive increase in CO. Above 0.8, an exponential rise in the CO emission rate is generally observed.

Currently, the DLN combustor is only used with gaseous fuels. A conventional combustor pilot burner operates continuously in the DLN combustor, and the pilot burner has sufficient capacity to supply 100 percent of the gas turbine's rated load. Due to flame instability at loads less than approximately 50 percent, the pilot provides all heat input to the gas turbine below 50 percent load.

ATTACHMENT B

ARB, Inc. Estimates: High Temperature VOC Catalyst

Description of Cost		Cost Factor	Cost ($)	Source
Direct Capital Costs (DC):				
Purchased Equip. Cost (PE	**Obtained budget cost from Peerless Mfg Co**			Peerless
Basic Equipment (A):	49.9 MW		550,000	Peerless
Auxiliary Equipment (B):	ammonia injection skid and storage	0.00 A *included*	0	Peerless
Instrumentation:	included in base price	0.00 A	0	Peerless
Taxes and freight:		0.08 A*B	44,000	OAQPS
PE Total:			594,000	
Direct Install. Costs (DI):				
Foundation		0.08 PE	53,000	ARB, Inc
Supports		0.14 PE	23,000	ARB, Inc
Electrical:		0.04 PE	5,000	ARB, Inc
Framing		0.02 PE	187,000	ARB, Inc
Insulation:		0.01 PE	17,000	ARB, Inc
Painting:		0.01 PE	10,000	ARB, Inc
DI Total:			295,000	
Site preparation and buildings:				
DC Total:			889,000	
Indirect Costs (IC):				
Engineering:		0.10 PE	125,000	ARB, Inc
Construction and field expenses:		0.05 PE	25,000	Estimate
Contractor Permit fees:		0.10 PE	50,000	Estimate
Start-up:	(7 days at 870 per day plus expenses)	0.02 PE	8,090	ARB, Inc
Performance testing:		0.01 PE	10,000	Estimate
Contingencies:		0.03 PE	15,000	Estimate
IC Total:			233,090	
Total Capital Investment (TCI = DC + IC):			1,122,090	
Direct Annual Costs (DAC):		hr/yr: 8,760		
Operating Costs (O):	sched. (hr/day): 24 day/week: 7	wk/yr: 52		
Operator:	hr/shift: 0.15 operator pay ($/hr): 25		4,095	Estimate
Supervisor:	15% of operator		614	Estimate
Maintenance Costs (M):				Estimate
Labor:	hr/shift: 0.20 labor pay ($/hr):	25	5,460	Estimate
Material:	% of labor cost: 100%		5,460	Estimate
Utility Costs:	thermal eff(%): 0 operating temp. (°F):			
Perf. loss:	(%): 0.25			
Electricity cost	($/kwh): 0.06 Performance loss, dP through Catalyst		65,389	variable
Catalyst replace:	assume 15 ft^3 catalyst per MW, $500/$ft^3$, 5 yr. guarantee		97,305	Peerless
Catalyst dispose:	$15/$ft^3$*15 ft^3/MW*MW*0.26 (5 yr. amortization period)		2,919	OAQPS
Total DAC:			181,242	
Indirect Annual Costs (IAC):			9,378	
Overhead:	60% of O&M		22,442	OAQPS
Administrative:		0.02 TCI		OAQPS
Insurance:		0.01 TCI	11,221	OAQPS
Property tax:		0.01 TCI	11,221	OAQPS
Capital recovery:	interest rate (%): 10			
	period (years): 15	0.13 TCI	134,732	OAQPS
Total IAC:			188,994	
Total Annual Cost (DAC + IAC):			**$370,236**	

VOC Emission Rate (tons/yr, uncontrolled):	less than 10 ppm	2.92 lb/hr	12.8
VOC Removed (tons/yr):	*control device removal eff.:*	*80 %*	10.2
Cost Effectiveness ($/ton):			$36,185